PB83-110700

Analysis of State and Federal Particulate and Visible Emission Regulations for Combustion Sources

PEDCo-Environmental, Inc.
Cincinnati, OH

Prepared for

Environmental Protection Agency
Research Triangle Park, NC

Jan 82

U.S. Department of Commerce
National Technical Information Service
NTIS

United States
Environmental Protection
Agency

Office of Air Quality
Planning and Standards
Research Triangle Park NC 27711

EPA-450/2-81-080
November 1981

Air

PB83-110700

EPA

Analysis of State and Federal Particulate and Visible Emission Combustion Sources

REPRODUCED BY
NATIONAL TECHNICAL
INFORMATION SERVICE
U.S. DEPARTMENT OF COMMERCE
SPRINGFIELD, VA 22161

TECHNICAL REPORT DATA

(Please read Instructions on the reverse before completing)

1. REPORT NO.	2.	3. RECIPIENT'S ACCESSION NO. PB83 110700
4. TITLE AND SUBTITLE Analysis of State and Federal Particulate and Visible Emission Regulations for Combustion Sources		5. REPORT DATE January 1982
		6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) David Dunbar, B.E. Blagun, and Donald J. Henz		8. PERFORMING ORGANIZATION REPORT NO. PN 3525-12
9. PERFORMING ORGANIZATION NAME AND ADDRESS PEDCo Environmental, Inc. 11499 Chester Road Cincinnati, Ohio 45246		10. PROGRAM ELEMENT NO.
		11. CONTRACT/GRANT NO. 68-02-3512 Work Assignment No. 12
12. SPONSORING AGENCY NAME AND ADDRESS U.S. Environmental Protection Agency Office of Air Quality Planning & Standards Research Triangle Park, North Carolina 27711		13. TYPE OF REPORT AND PERIOD COVERED Final
		14. SPONSORING AGENCY CODE

15. SUPPLEMENTARY NOTES

U.S. EPA Project Office - Kenneth R. Woodard

16. ABSTRACT

This document provides a compilation of the particulate and visible emission limits from the State Implementation Plans (SIP's) and Federal Standards of Performance for New Stationary Sources that are applicable to fuel combustion sources. A comparison of mass emission rates along with a summary of the mass and visible emission regulations by state or territory is presented. This document also provides our overview of the emissions from boilers and the control techniques typically being used to meet the current SIP requirements.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Air Pollution	State Implementation Plan	13B
	New Source Performance Standards	
Combustion	Emission Regulations	21B
Opacity	Visible Emissions	14G
Particles	Particulate Emissions	

18. DISTRIBUTION STATEMENT Unlimited	19. SECURITY CLASS *(This Report)* Unclassified	21. NO. OF PAGES 212
	20. SECURITY CLASS *(This page)* Unclassified	22. PRICE

EPA Form 2220-1 (9-73)

EPA-450/2-81-080

Analysis of State and Federal Particulate and Visible Emission Regulations for Combustion Sources

by

PEDCo Environmental, Inc.
11499 Chester Road
Cincinnati, Ohio 45246

Contract No. 68-02-3512
Work Assignment No. 12
PN 3525-12

Project Officer: Kenneth R. Woodard

U.S. ENVIRONMENTAL PROTECTION AGENCY
Control Programs Development Division
Research Triangle Park, North Carolina 27711

November 1981

This report is issued by the Environmental Protection Agency to report technical data of interest to a limited number of readers. Copies are available - in limited quantities - from the Library Services Office (MD-35), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; or, for a fee, from the National Technical Information Service, 5285 Port Royal Road, Springfield, Virginia 22161.

Publication No. EPA-450/2-81-080

CONTENTS

Page

Figures iv
Tables v
Acknowledgment vi

1. Introduction 1

2. Nationwide Summary of Mass Emission Rates 3

3. Regulation of Particulate Emissions from Fuel Combustion 13

    3.1 Regulation under the Clean Air Act 13
    3.2 State Implementation Plans 14
    3.3 Federal Standards of Performance for New Sources 20

4. Boiler Emissions and Control Techniques 24

    4.1 Control of Particulate Emissions 24
    4.2 Relationship Between Allowable Emissions and Other Parameters 32

5. Compilation of Particulate Mass and Visible Emission Limits 35

    5.1 Summary of Mass and Visible Emission Regulations by State or Territory 35
    5.2 Summary of Continuous Monitoring Requirements for Opacity 37
    5.3 State and Territory Specific Summaries 38

References 109

Appendix A Reference figures for allowable emission rates 113
Appendix B Conversion factors 170
Appendix C Method 5--Determination of particulate emissions from stationary sources 173

FIGURES

Number		Page
1	Histogram of Emission Limits for Selected Boiler Sizes	9
2	Typical Mass Rate Regulation Applicable to Solid Fuel-fired Boilers Based on Equipment Capacity	15
3	Typical Mass Rate Regulation Applicable to Solid Fuel-Fired Boilers Based on Firing Rate	16
4	Range of Boiler Sizes by Use	25
5	Relative Uncontrolled Particulate Emissions from Various Fuel/Boiler Combinations	26
6	Control Efficiency vs. Particle Size for Mechanical Collectors	29
7	Relationship between Collection Efficiency and SCA for Various Coal Sulfur Contents	30
8	Nomograph for Relating Allowable Emissions and Overall Control Efficiency	33
9	Particulate Emission Rates for a Typical Pulverized Coal-Fired Boiler	34

TABLES

Number		Page
1	Summary of Allowable Mass Emission Rates for Indirect Heat Exchangers	4
2	Conversion Factors for Particulate Emission Regulations	10
3	Comparison of Allowable Particulate Emissions under Various Interpretations of the Regulations for Two Co-Fired Furnaces Rated at 200 × 10^6 Btu/h Each	17
4	Comparison of Light Extinction Terms	19

ACKNOWLEDGEMENT

This report was prepared for the U.S. Environmental Protection Agency by PEDCo Environmental, Inc., Cincinnati, Ohio. Mr. Kenneth Woodard was the Project Officer. Mr. Donald Henz served as the Project Director and Mr. David Dunbar was the Project Manager. The principal authors were Ms. Barbara Blagun, Mr. David Dunbar, and Mr. Donald Henz. The authors wish to thank Mr. Kenneth Woodard for his overall guidance and direction and Mr. John Calcagni for his comments and suggestions. The authors also wish to thank Mr. Willis Beal for his assistance in locating the files on the State Implementation Plan requirements.

SECTION 1

INTRODUCTION

The purpose of this report is to compile the particulate and visible emission limits from the State Implementation Plans (SIP's) and Federal standards of performance for new stationary sources that are applicable to fuel combustion sources. This report was developed to serve as a starting point for broad control strategy evaluations and is not intended to be a precise reference for individual compliance determinations. Users are cautioned to contact the appropriate State and/or local air pollution control agency and EPA Regional Office to verify the specific emission limits applicable to an individual source. The definition of fuel combustion varies from State to State, but in all cases, fuel combustion regulations apply to utility and industrial boilers that burn fuel to generate steam. The regulations compiled in this report generally do not apply to particulate emissions from incineration or industrial processes.

The SIP's are designed to ensure that all areas within a State attain and maintain the National Ambient Air Quality Standards (NAAQS's). Although most regulations in an SIP are State regulations, there are some cases where a State has chosen to include a local regulation as part of the SIP. Therefore, this report includes not only those State regulations that represent the SIP for an individual State or territory but also those local regulations that are considered to be part of the SIP as well.

The basic references for this report are a series of reports prepared for the U.S. Environmental Protection Agency (EPA)[1-55] as a result of the Clean Air Act Amendments of 1977. The 1977 Act amendments required EPA to prepare an official SIP compilation for each State or territory. These compilations represented all the regulations contained in the SIP's as of July 1, 1979. However, because some regulatory actions have been taken over the past several years to revise the SIP's to comply with the 1977 Act amendments, PEDCo reviewed all Federal Register notices published between July 1, 1979, and April 1, 1981, to determine if any revisions to the SIP fuel combustion regulations were made since July 1, 1979. In addition, PEDCo also reviewed the current State regulations published in the Environment Reporter as of April 1, 1981, to ensure that the SIP regulations contained in this report represent the most current SIP regulations applicable to fuel combustion sources. As a final check, the compilation of regulations contained in this report was compared to the summary of SIP regulations for fuel combustion sources published by EPA in August 1976.[56] During this comparison, some questions arose regarding the form or applicability of the equations used in the regulations. As a result, contacts were made to individual States to clarify these questions.

In this report, Section 2.0 summarizes and compares the mass emission rates for all 50 States, the District of Columbia, and the four territories. Section 3.0 discusses regulation of particulate emissions from fuel combustion sources. Section 4.0 discusses emissions from and control techniques used for boilers. Section 5.0 compiles the particulate mass and visible emission regulations by State and political jurisdiction.

Appendix A contains figures referred to in the compilation of the State and local regulations (Section 5.0); these are graphical representations of the equations or tables used to calculate the allowable emissions for individual fuel combustion sources. Appendix B lists some conversion factors commonly associated with fuel combustion sources and their applicable regulations. Appendix C contains a copy of EPA Reference Method 5.

SECTION 2

NATIONWIDE SUMMARY OF MASS EMISSION RATES

Table 1 summarizes the mass emission rates for all 50 States, the District of Columbia, and the four territories. This table indicates how the allowable emissions are to be applied, such as entire plant, an individual boiler or an individual stack. This table also presents the allowable limits in lb/10^6 Btu for typical sizes of new and existing boilers. Because all the State regulations are not expressed in terms of lb/10^6 Btu some conversion was necessary in order to compare typical size boiler or combustion units. Table 2 lists the conversion factors and the assumptions used to convert the emission limits of the individual regulations to lb/10^6 Btu.

All of the new source emission limits listed in Table 1 do not represent the New Source Performance Standard (NSPS) limits in all cases. Although some States have adopted the NSPS limits as promulgated by EPA, others have developed their own more stringent limits especially for sources less than 250 × 10^6 Btu/h, because the NSPS limits do not apply to these size units. Additionally, some States do not require new sources to meet any limit more stringent than that required of existing sources. In those cases, no number is presented in Table 1.

Table 1 indicates for small units (10 × 10^6 Btu or less) that allowable emission limits vary from 0.10 to 1.2 lb/10^6 Btu and that most limits are between 0.4 and 0.8 lb/10^6 Btu. For existing 250 × 10^6 Btu/h units, allowable emission limits vary from 0.05 to 0.8 lb/10^6 Btu with most States having a limit between 0.1 and 0.5 lb/10^6 Btu. Finally, for the existing larger units, i.e., 10,000 × 10^6 Btu/h or more, the allowable limits vary from 0.01 to 0.8 lb/10^6 Btu, with over half of the States having a limit between 0.1 and 0.20 lb/10^6 Btu. Figure 1 is a histogram of emission limits for 250 × 10^6 Btu/h, 1000 × 10^6 Btu/h, and 10,000 × 10^6 Btu/h units. With respect to applicability, over half the States apply the regulations on an individual stack basis with the remainder of the States almost evenly divided between applying the regulations to the individual unit or the entire plant.

TABLE 1. SUMMARY OF ALLOWABLE MASS EMISSION RATES FOR INDIRECT HEAT EXCHANGERS

State	Allowable emissions based on:				Existing source limits for typical units, lb/10^6 Btu					New source limits for typical units, lb/10^6 Btu					Footnotes
	Entire plant	Individual unit	Individual stack	Other	10×10^6 Btu/h	100×10^6 Btu/h	250×10^6 Btu/h	1000×10^6 Btu/h	$10,000 \times 10^6$ Btu/h	10×10^6 Btu/h	100×10^6 Btu/h	250×10^6 Btu/h	1000×10^6 Btu/h	$10,000 \times 10^6$ Btu/h	
Alabama			X												
Class I					.50	.18	.12	.12	.12	.5	.18	.12	.12	.12	^{a}Existing .10 gr/scf, new .05 gr/scf assuming 50% excess air - coal.
Class II					.80	.21	.12	.12	.12	.5	.18	.12	.12	.12	
Alaska		X			.20^a .21^b	.20^a .21^b	.20^a .21^b	.20^a .21^b	.20^a .21^b	.10^a .11^b	.10^a .11^b	.10^a .11^b	.10^a .11^b	.10^a .11^b	^{b}Existing .10 gr/scf, new .05 gr/scf assuming 50% excess air - oil.
Arizona			X		.60	.35	.28	.21	.09						
Arkansas	X				1.2	.75	.56	.24	.07						^{c}No Statewide regulations.
California^c															
Colorado			X		.27	.16	.14	.10	.10			.10	.10	.10	
Connecticut	X				.20	.20	.20	.20	.20	.10	.10	.10	.10	.10	
Delaware		X			.30	.30	.30	.30	.30						
District of Columbia			X		.10	.06	.05	.03	.02						
Florida		X			.10	.10	.10	.10	.10	.10	.10	.10	.10	.10	
Georgia		X			.70	.44	.37	.28	.24	.50	.16	.10	.10	.10	
Hawaii		X													

(continued)

Note: New source performance standards (40 CFR 60.40 and 60.40a) supersede less stringent State emission limits where applicable.

TABLE 1 (continued)

State	Allowable emissions based on:				Existing source limits for typical units, lb/10⁶ Btu					New source limits for typical units, lb/10⁶ Btu					Footnotes
	Entire plant	Individual unit	Individual stack	Other	10 x 10⁶ Btu/h	100 x 10⁶ Btu/h	250 x 10⁶ Btu/h	1000 x 10⁶ Btu/h	10,000 x 10⁶ Btu/h	10 x 10⁶ Btu/h	100 x 10⁶ Btu/h	250 x 10⁶ Btu/h	1000 x 10⁶ Btu/h	10,000 x 10⁶ Btu/h	
Idaho				X	.60	.36	.29	.20	.12						[d] Chicago metropolitan area.
Illinois[d]			X		1.0	.19	.10	.10	.10	.10	.10	.10	.10	.10	[e] Outside major metropolitan Chicago.
Illinois[e]			X		.10	.10	.10	.10	.10	.10	.10	.10	.10	.10	[f] All areas except Lake and Porter Counties and Indianapolis AQCR - missing values dependent upon stack height.
Indiana[f]	X				.80	.80	.80			.60					
Indiana[g]	X				.60	.40	.35	.28	.20			.10	.10	.10	
Iowa[h]			X		.60	.60	.60			.60	.60	.60			[g] Lake and Porter Counties and Indianapolis AQCR.
Iowa[i]			X		.80	.80	.80			.60	.60	.60			
Kansas			X		.60	.35	.28	.21	.12						[h] Inside SMSA - missing values dependent upon stack height.
Kentucky[j]		X			.56	.33	.26	.19	.11	.56	.33	.10	.10	.10	
Kentucky[k]		X			.75	.44	.35	.26	.15	.56	.33	.10	.10	.10	[i] Outside SMSA - missing values dependent upon stack height.
Kentucky[l]		X			.80	.49	.34	.30	.18	.56	.33	.10	.10	.10	
Louisiana	X				.60	.60	.60	.60	.60						[j] Priority I areas.
Maine			X		.60	.34	.30	.30	.30						[k] Priority II areas.
Maryland			X		.60	.35	.28	.21	.12	.4	.22	.10	.10	.10	[l] Priority III areas.

(continued)

Note: New source performance standards (40 CFR 60.40 and 60.40a) supersede less stringent State emission limits where applicable.

TABLE 1 (continued)

State	Allowable emissions based on:				Existing source limits for typical units, lb/10^6 Btu					New source limits for typical units, lb/10^6 Btu					Footnotes
	Entire plant	Individual unit	Individual stack	Other	10 × 10^6 Btu/h	100 × 10^6 Btu/h	250 × 10^6 Btu/h	1000 × 10^6 Btu/h	10,000 × 10^6 Btu/h	10 × 10^6 Btu/h	100 × 10^6 Btu/h	250 × 10^6 Btu/h	1000 × 10^6 Btu/h	10,000 × 10^6 Btu/h	
Massachusetts			X		$.15^{m}$	.15	.15	.15	.15	.10	.10	.10	$.05^{n}$	$.05^{n}$	[m] Critical areas limit is 0.12 Berkshire, Central Mass., Merrimack Valley, Metro. Boston Pioneer Valley, S.E. Mass Air Pollution Control Districts.
Michigan		X			$.38^{o}$ $.35^{p}$	$.38^{o}$ $.35^{p}$	$.33^{o}$ $.30^{p}$	$.23^{o}$ $.21^{p}$	$.23^{o}$ $.21^{p}$						
Minnesota			X		$.60^{q}$	$.60^{q}$	$.60^{q}$	$.60^{q}$	$.60^{q}$	$.40^{r}$	$.40^{r}$	$.40^{r}$	$.40^{r}$	$.40^{r}$	[n] 0.10 allowed if equipment is used to control or reduce SO_2 at the same time.
Mississippi	X				.60	.40	.35	.28	.19						
Missouri			X		.60	.40	.36	.26	.18	.60	.275	.232	.126	.10	[o] Conversion from lb/1000 lb stack gas coal.
Montana			X		.60	.40	.35	.28	.19	.60	.35	.10	.10	.10	[p] Conversion from lb/1000 lb stack gas oil.
Nebraska	X				.60	.35	.28	.21	.15						[q] Also applies to sources located outside the Minneapolis-St. Paul AQCR and the City of Duluth.
Nevada	X				.60	.35	.28	.21	.09						
New Hampshire			X		.60	.40	.35	.28	.19	.60	.35	.10	.10	.10	[r] Also applies to sources located within the Minneapolis-St. Paul AQCR and the City of Duluth.
New Jersey			X		.60	.15	.10	.10	.10						
New Mexico		X			.70	.50	.50	.50	.50	.56	.33	.27	.19	.14	[s] No handfired bituminous coal units.
New York[s,t]			X		.60	.37	.30	.23	.14	.60	.37	.10	.10	.10	[t] No oil units $\leq$ 10 lb/10^6 Btu.
North Carolina			X		.60 $.70^{u}$	.33 $.41^{u}$	.26 $.34^{u}$	.18 $.25^{u}$	.10 $.15^{u}$						[u] Wood burning.

(continued)

Note: New source performance standards (40 CFR 60.40 and 60.40a) supersede less stringent State emission limits where applicable.

TABLE 1 (continued)

State	Allowable emissions based on:				Existing source limits for typical units, lb/10^6 Btu					New source limits for typical units, lb/10^6 Btu					Footnotes
	Entire plant	Individual unit	Individual stack	Other	10 × 10^6 Btu/h	100 × 10^6 Btu/h	250 × 10^6 Btu/h	1000 × 10^6 Btu/h	10,000 × 10^6 Btu/h	10 × 10^6 Btu/h	100 × 10^6 Btu/h	250 × 10^6 Btu/h	1000 × 10^6 Btu/h	10,000 × 10^6 Btu/h	
North Dakota			X		.80	.80	.80	.80	.80	.60	.44	.10	.10	.10	[v] Priority I Regions. [w] Priority II & III Regions. [x] .2 gr/scf assuming 50% excess air - coal fired. [y] .2 gr/scf assuming 50% excess air - oil fired. [z] .1 gr/scf assuming 50% excess air - coal fired. [aa] .1 gr/scf assuming 50% excess air - oil fired. [bb] Solid fossil fuel fired steam generators only. [cc] New fossil-fuel fired steam generators only. [dd] Value is for AQCR #1-6 value for AQCR #7 is .30. All other values are the same as AQCR 1-6.
Ohio			X		.40[v] .60[w]	.20[v] .60[w]	.15[v] .30[w]	.10[v] .15[w]	.10[v] .15[w]						
Oklahoma		X			.60	.35	.28	.20	.10						
Oregon			X		.46[x] .43[z]	.46[x] .43[z]	.46[x] .43[z]	.46[x] .43[z]	.46[x] .43[z]	.23[y] .21[aa]	.23[y] .21[aa]	.23[y] .21[aa]	.23[y] .21[aa]	.23[y] .21[aa]	
Pennsylvania		X			.40	.27	.16	.10	.10						
Rhode Island			X		.20	.20	.10	.10	.10						
South Carolina			X		.80	.60	.60	.60	.16	.60	.60	.60	.60	.16	
South Dakota	X				.30	.30	.30	.30	.30			.10	.10	.10	
Tennessee			X		.60	.33	.26	.18	.10	.60	.17	.10	.10	.10	
Texas		X			.30[bb]	.30[bb]	.30[bb]	.30[bb]	.30[bb]						
Utah		X			.60	.42	.36	.29	.20	.10[cc]	.10[cc]	.10[cc]	.10[cc]	.10[cc]	
Vermont			X		.50	.18	.10	.10	.06						
Virginia			X		.40[dd]	.29	.23	.17	.01						

(continued)

Note: New source performance standards (40 CFR 60.40 and 60.40a) supersede less stringent State emission limits where applicable.

TABLE 1 (continued)

State	Allowable emissions based on:				Existing source limits for typical units, lb/10⁶ Btu					New source limits for typical units, lb/10⁶ Btu					Footnotes
	Entire plant	Individual unit	Individual stack	Other	10 x 10⁶ Btu/h	100 x 10⁶ Btu/h	250 x 10⁶ Btu/h	1000 x 10⁶ Btu/h	10,000 x 10⁶ Btu/h	10 x 10⁶ Btu/h	100 x 10⁶ Btu/h	250 x 10⁶ Btu/h	1000 x 10⁶ Btu/h	10,000 x 10⁶ Btu/h	
Washington	X				.46[ee] .43[ff]	.46[ee] .43[ff]	.46[ee] .43[ff]	.46[ee] .43[ff]	.46[ee] .43[ff]	.23[ee] .21[ff]	.23[ee] .21[ff]	.23[ee] .21[ff]	.23[ee] .21[ff]	.23[ee] .21[ff]	[ee]Existing .20 gr/dscf, new .10 gr/dscf assuming 50% excess air - coal.
West Virginia	X				.34	.17	.09	.09	.09						[ff]Existing .20 gr/dscf, new .10 gr/dscf assuming 50% excess air - oil.
Wisconsin			X		.60 .30[gg] .15[hh]	.60 .30[gg] .15[hh]	.60 .30[gg] .15[hh]	.25 .25 .15[hh]	.15 .15 .15[hh]	.15	.15	.15	.10	.10	[gg]Subregion of Lake Michigan AQCR. [hh]Sources in S.E. Wisconsin AQCR.
Wyoming			X		.60	.40	.34	.27	.20	.10	.10	.10	.10	.10	[ii]Did not specify.
American Samoa	X				.10	.10	.10	.10	.10						
Guam				x[ii]											
Puerto Rico			X		.30	.30	.30	.30	.30						
Virgin Islands		X			.60	.35	.33	.21	.09						

Note: New source performance standards (40 CFR 60.40 and 60.40a) supersede less stringent State emission limits where applicable.

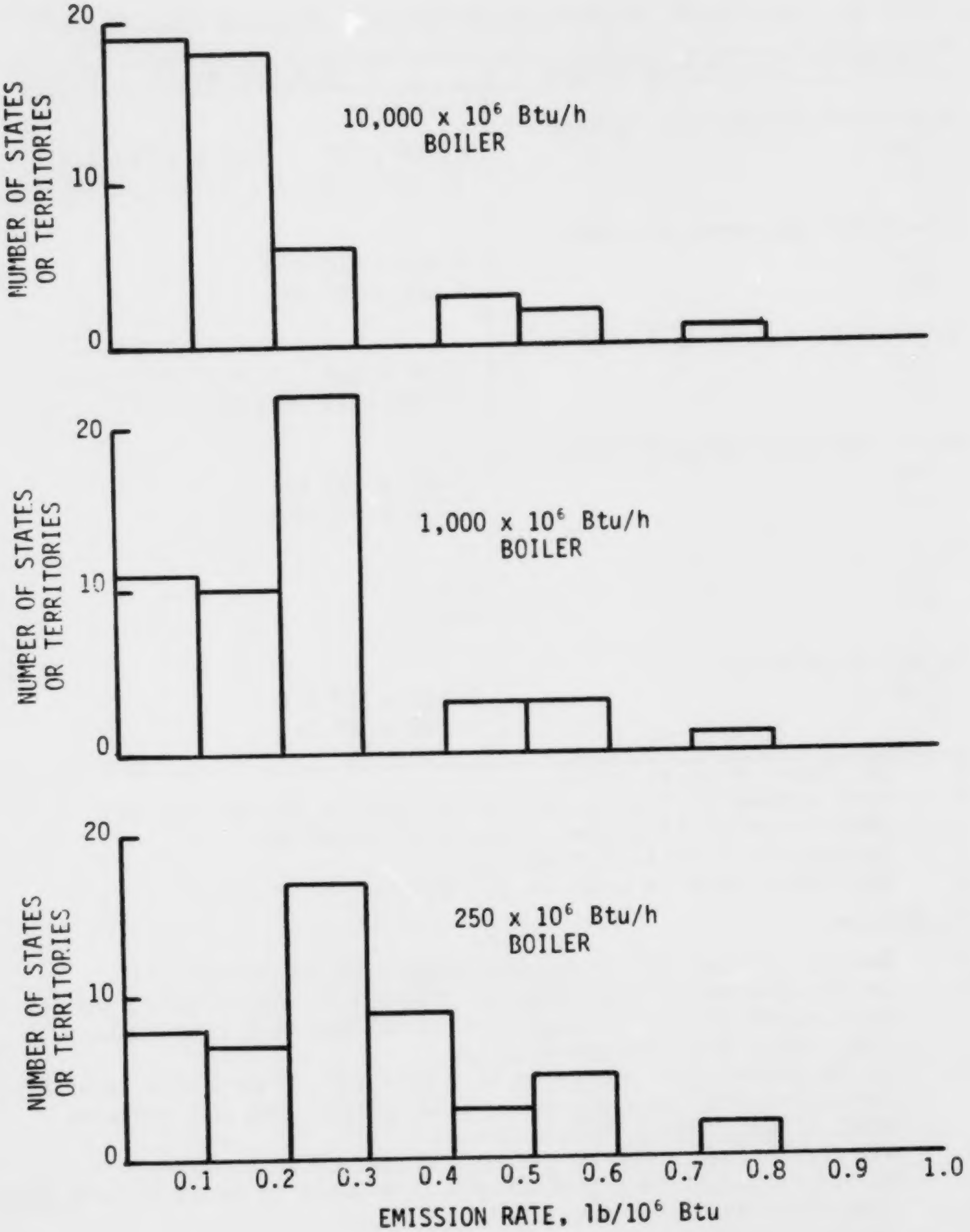


Figure 1. Histogram of emission limits for selected boiler sizes.

TABLE 2. CONVERSION FACTORS FOR PARTICULATE EMISSION REGULATIONS[56]

Units of the regulation (A)	E(lb/10^6 Btu)
grains/SCF (assuming X is known)	
Coal	$(1.99 \times 10^4 + 1.89 \times 10^2X)$ A/H
Oil	$(2.094 \times 10^5 + 1.993 \times 10^3X)$ A/H
grains/SCF (assuming X = 50%)	
Coal	2.905×10^4 A/H
Oil	3.091×10^5 A/H
grains/SCFD (assuming X is known)	
Coal	$(1.96 \times 10^4 + 1.89 \times 10^2X)$ A/H
Oil	$(2.094 \times 10^5 + 1.993 \times 10^3)$ A/H
grains/SCFD (assuming X = 50%)	
Coal	2.905×10^4 A/H
Oil	3.091×10^5 A/H
lb/h	
Coal	A/Q
Oil	A/Q
lb/10^3 lb stack gas	
Coal	1.596×10^4 A/H
Oil	1.668×10^5 A/H

A SIP value in given units
H Heat content of fuel in Btu/lb for coal or Btu/gal for oil
E Emission of particulates in units of lb/10^6 Btu
X Excess air in units of % excess
Q Heat input rate in units of 10^6 Btu/h

Assumptions:

1. Density of fuel oil is assumed to be 7.88 lb oil/gal oil.
2. In the conversion from units of grains/SCF, grains/SCFD, and lb particulate/10^3 lb stack gas, it is assumed that coal contains 72%C, 5%H_2, 1%S, and 10% moisture.
3. In the conversion from units of grains/SCF, grains/SCFD, and lb particulate/10^3 lb stack gas, it is assumed that oil contains 88%C, 9.5%H_2, and 0.5% moisture.
4. Air fed to the boiler is assumed to contain no moisture.
5. Molecular weight of the stack gas is assumed to be 29.5 lb/lb mole.
6. Complete combustion is assumed.
7. Standard conditions for stack gas is taken as 1 atmosphere and 60°F.
8. Stack gas is assumed to be an ideal gas.
9. Heat content of coal is assumed to be 1.25×10^4 Btu/lb.
10. Heat content of oil is assumed to be 1.45×10^5 Btu/gal.

For new sources, the allowable emission limits for units less than 250 × 10^6 Btu/h vary from 0.1 to 0.6 lb/10^6 Btu. For new sources with units greater than 250 × 10^6 Btu/h, the limits are generally 0.1 lb/10^6 Btu or less; however, some limits are above 0.1 lb/10^6 Btu. In cases where an NSPS source would be involved, State emission limits above 0.1 lb/10^6 Btu would not be applicable because the NSPS limits require sources to meet 0.1 lb/10^6 Btu or less (0.03 lb/10^6 for steam electric generating units greater than 250 × 10^6 Btu/h).

In addition to Table 1, which compares selected unit sizes, Appendix A contains a series of reference figures that provide a graphical representation of the allowable limits for the full size range of units covered by the various State regulations. Although the general shape of the figures is the same, the emission limits associated with certain size units vary. In some cases, the stringency of the limit, i.e., lb/10^6 Btu, is the same for all units less than 10 x 10^6 Btu/h. In other cases, however, the size of the unit where the stringency of the limit remains constant is 100 or 250 × 10^6 Btu/h. On the other end of the scale, the size of the unit beyond which the stringency of the limit remains constant is usually 10,000 x 10^6 Btu/h; although in some cases, the size of the unit where the stringency of the limit remains constant is 1000 or 3000 x 10^6 Btu/h. Therefore, the reference figures provide an additional method for comparing the overall SIP requirements for fuel combustion sources.

It is difficult to draw absolute conclusions regarding the stringency of one State's requirements as compared to another. In some cases, one State may be more stringent than another with respect to smaller units but less stringent with respect to larger units, or vice versa. In other cases, there are exemptions for certain size sources or for particular fuel types that make it difficult to compare the emission limits. Since not all regulations are in the same units, assumptions were made to convert the emission limit units to lb/10^6 Btu. Although these assumptions are reasonable, they are only estimates and the absolute number in lb/10^6 Btu can only be calculated on a case-by-case basis with specific source information. Finally, because the air quality problems across the country vary from region to region, the relative stringencies of the requirements vary. In some cases, the States are concerned with reducing air quality levels which are far in excess of the

NAAQS's; while in cases, the States are concerned with maintaining current air quality levels, and therefore do not have to require the same level of control from all sources in all areas of the State. Thus, while there is some variability in the overall SIP requirements for fuel combustion sources, in many cases this variability can be justified based on the air quality problems that may exist in a specific area.

SECTION 3

REGULATION OF PARTICULATE EMISSIONS FROM FUEL COMBUSTION

3.1 REGULATION UNDER THE CLEAN AIR ACT

The Clean Air Act of 1970 gave the EPA the responsibility and authority to control air pollution in the United States and its territories. One of the responsibilities given to EPA under Section 109 of the Act was the promulgation of NAAQS's. In addition to giving EPA certain authority, the Act also required the States under Section 110 to adopt and submit to EPA their plans for attaining and maintaining the NAAQS's in all regions of the State. Each State, therefore, decided which existing emission sources should be controlled and to what extent. Particulate emissions from fuel combustion sources were one of the first targets of State air pollution control regulations.

In addition, Section 111 of the Clean Air Act gave EPA the authority to develop performance standards for new stationary sources. The NSPS's established at a national level apply to both new and modified sources. The NSPS's must reflect the degree of emission reduction achievable through the application of the best system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, and any nonair quality, health, and environmental impact and energy requirements) the EPA Administrator determines has been adequately demonstrated for a source category.

In addition to limiting the mass emission rate, the opacity of boiler stack plumes is also regulated. Allowable plume opacities vary with the jurisdictions. A maximum allowable opacity of 20 percent is common. However, nearly all jurisdictions allow for periodic excursions. For example, the NSPS for utility boilers allows a plume opacity greater than 20 percent for a period not to exceed six minutes per hour. This type of provision originates from the need to periodically remove soot deposits from the boiler tubes by directing a jet of steam against the outside tube walls (soot blowing). Because soot blowing causes a significant increase in potential emissions, the early visible emission regulations allowed for brief periods of high plume densities. Although utility boilers often blow soot continuously, soot is only blown one to three times a day on industrial boilers. Hence, the current provision for brief periods of higher plume density is designed to allow for brief, insignificant, malfunctions in the combustion process or the control system.

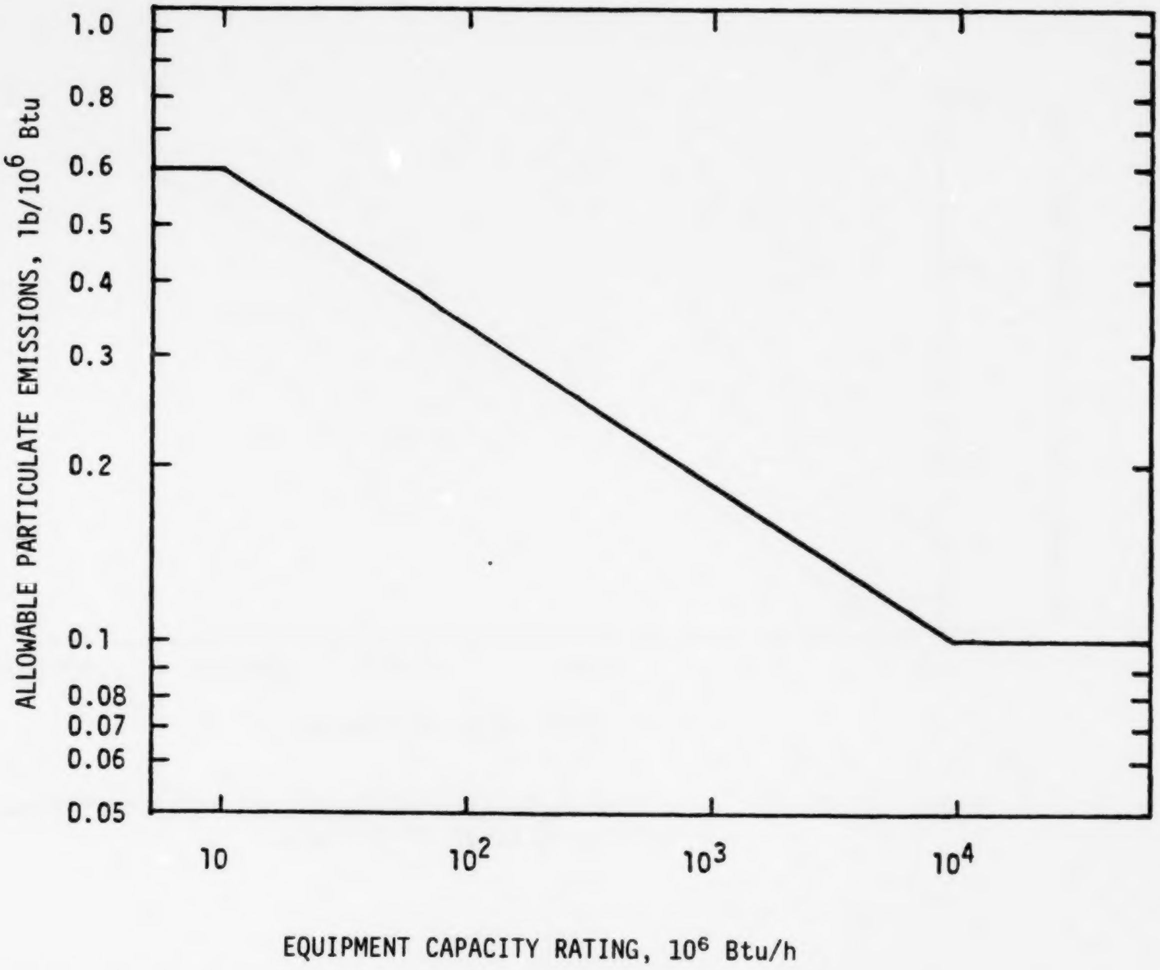
3.2 STATE IMPLEMENTATION PLANS

Pursuant to the Clean Air Act, each State must adopt and submit to EPA a plan that provides for attainment and maintenance of the NAAQS in all areas of the State. The SIP must include emission limitations, schedules, timetables and other measures that may be necessary to ensure attainment and maintenance of the NAAQS. Each State determines the mix of emissions limitations that would be applicable to the sources within the State.

3.2.1 Typical Mass Rate Emission Regulations

Particulate emissions from fossil-fuel-fired combustion sources are most often limited by the heat input (capacity) of the boiler. A typical regulation based on equipment capacity is graphically shown in Figure 2; a typical one based on fuel-firing rate is shown in Figure 3. Sometimes the regulation (abscissa in Figure 3) specifies heat input rather than equipment capacity. This raises a question whether allowable emissions vary with the firing rate, or if the maximum firing rate (or capacity) establishes a fixed allowable emission rate. Other questions raised by typical regulations are:

- For multifueled units (cofiring), is the energy content of all the fuel counted, or only that portion of heat input attributable to one of the fuels?
- For multiunit/one-stack units, is the heat rate or capacity based on the sum of all units, or on each unit separately?
- For multiunit/multistack units, is the heat rate or the capacity based on the sum of all units, the sum of all units served by a particular stack, or on each unit separately?



EQUIPMENT CAPACITY RATING, 10^6 Btu/h

Figure 2. Typical mass rate regulation applicable to solid fuel-fired boilers based on equipment capacity.

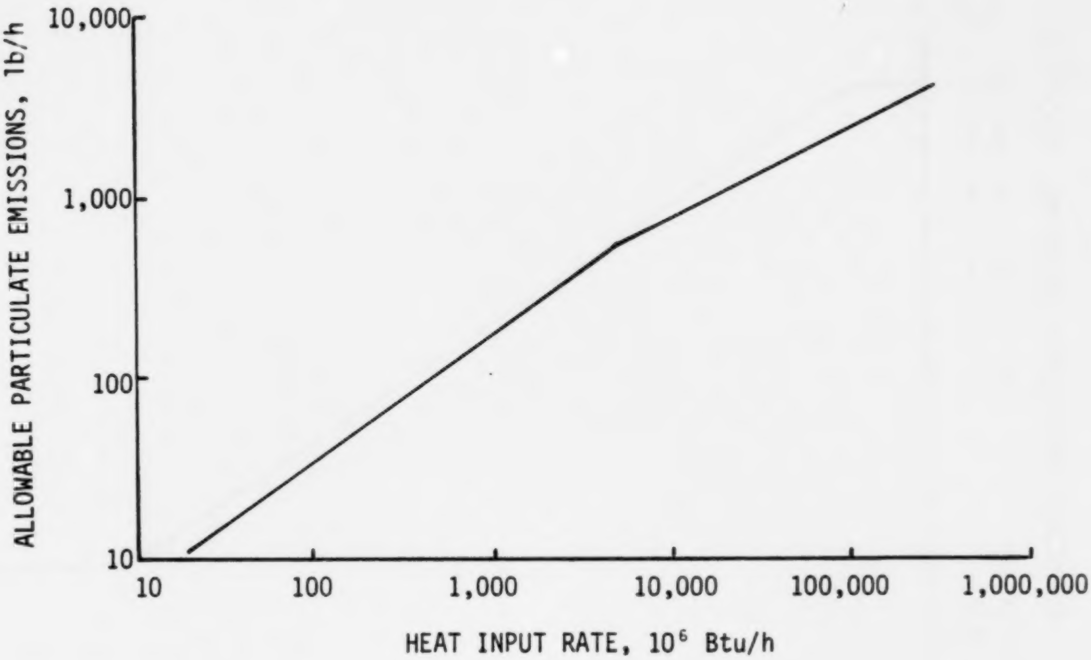


Figure 3. Typical mass rate regulation applicable to solid fuel-fired boilers based on firing rate.

Table 3 illustrates how the allowable emissions may vary depending on the interpretation of the regulations. Application of a given particulate emission regulation requires that the following questions be answered:

- To what type and size of fuel-burning unit does the regulation apply?
- To what type of fuel does the regulation apply?
- How is unit size calculated?
- How is capacity or heat input determined?
- For cofired units is heat input from all fuels considered, or only that from specified fuels?

TABLE 3. COMPARISON OF ALLOWABLE PARTICULATE EMISSIONS UNDER VARIOUS INTERPRETATIONS OF THE REGULATIONS FOR TWO COFIRED[a] BOILERS RATED AT 200 × 10^6 Btu/h EACH

Interpretation of regulation	Total allowable emissions: Regulation per Figure 2[b] lb/10^6 Btu	Regulation per Figure 2[b] lb/h	Regulation per Figure 3[c] lb/h
No differentiation regarding fuel; sum of all units (400 × 10^6 Btu/h)	0.230	92.2	102.2
No differentiation regarding fuel; each unit considered separately	0.276 each unit	110.3	120.0 each unit
Considers heat input of coal only; sum of all units (400 × 10^6 Btu/h)	0.276	55.2	60.0
Considers heat input of coal only; each unit considered separately	0.330	66.0	70.4

[a] Each unit is fired with 100 × 10^6 Btu/h coal; 100 × 10^6 Btu/h oil

[b]

$$\text{Allowable emissions} = 1.0903 \left(\frac{\text{capacity rating}}{10^6}\right)^{-0.2594}$$

[c]

$$\text{Allowable emissions} = 1.02 \left(\frac{\text{heat input rate}}{10^6}\right)^{0.760}$$

3.2.2 Typical Opacity Regulations

The visible emission regulations in most States are general in wording and broad in terms of overall applicability. Although some States or local agencies have identified specific source categories to which a particular opacity standard would apply, most States have an opacity requirement that applies to practically all stationary sources. The most common terminology for applicability is "all existing sources." Other terms include "existing equipment," "existing facilities," "stationary sources," "process operations," and "existing installations." The use of "all existing sources" essentially makes all sources subject to the requirement. Although a few States have opacity requirements that specifically apply to fuel-burning sources, most States have a general opacity requirement that applies to all sources, including fuel-burning sources.

A wide range of visible emission regulations exists across the United States. The specific requirements are listed in Section 5.0 by State and by political jurisdication within each State. The visible emission or opacity requirements are almost evenly divided between the Ringelmann chart and opacity. Some State or local agencies specify only the Ringelman number; others specify the Ringelmann number and an equivalent opacity limit; and still others only specify an opacity limit.

The visible emission system in the United States is derived from the technical concept developed in the 1800's by Maxmillian Ringelmann to measure black smoke emissions from coal-fired boilers. The Ringelmann chart was adopted in the early 1900's by the U.S. Bureau of the Mines and was used extensively by State and local agencies to evaluate emissions from coal-fired boilers. Because the Ringelmann chart can only be used for black smoke, the concept of opacity as a measure of all colors of emissions was introduced in the early 1950's. Opacity is the degree of obscuration of an object behind the smoke plume, rather than the appearance of the plume itself. Light transmittance (incident light flux/light flux leaving the plume), opacity, and Ringelmann are compared in Table 4.

TABLE 4. COMPARISON OF LIGHT EXTINCTION TERMS

Light transmittance, %	Plume opacity, %	Ringelmann number
0	100	5
0.20	80	4
0.40	60	3
0.60	40	2
0.80	20	1
1.00	0	0

Most States and local agencies allow visible emissions to exceed a prescribed standard for some finite period of time; the usual period is 3 to 5 minutes in any one hour but a few agencies allow an excursion for 6 to 8 minutes in any one hour. A few agencies define the excursion (or exception) as the total minutes in a day that the standard may be exceeded. A very few agencies do not allow any period of excursion above the prescribed standard.

The one exemption that applies almost universally to opacity standards is the exclusion of uncombined water vapor from the opacity reading. The wording of this exemption is usually as follows "where the presence of uncombined water is the only reason for failure of an emission to meet the requirements, such sections of the opacity requirements shall not apply."

3.2.3 Testing, Monitoring, and Reporting Requirements

Because compliance with the applicable mass emission regulation is determined by a source stack test, the associated test procedures are very important. For example, if the mass emission regulation defines particulate matter to include condensible material, the particulate matter collected in the impingers in the back half of the sampling train (Appendix C) must be considered. The measured particulate matter is also affected by the operating temperature of the filter--the lower the temperature, the higher the catch of condensible matter. Thus an in-stack filter, such as the type used in American Society of Mechanical Engineers (ASME's) Power Test Code 27 (PTC-27) method, would probably capture less than an EPA Method 5 (40 CFR 60, Appendix A) filter maintained at 250°F. The specified test procedure should delineate:

1. the applicable traversing method;
2. the method of determining gas velocity and flow rate;
3. the method of analyzing for moisture, carbon monoxide, oxygen, and excess air, and for determining the dry molecular weight of the gas; and
4. the method of determining particulate emissions.

The most widely used particulate sampling methods are EPA Method 5 and ASME's PTC-27. The latter generally delineates the above items while the former only specifies how the particulate matter is determined. The other items critical to calculating the emissions are delineated in great detail in EPA Methods 1, 2, 3, and 4 (40 CFR 60 Appendix A). Because Method 5 cannot be properly implemented without Methods 1 through 4, the requirement for Method 5 infers the use of Methods 1 through 4.

In the case of visible emissions, many control agencies use visual observations by field inspectors to certify compliance. Other jurisdictions require continuous in-stack opacity monitors. These monitors may be used with or without ancilliary recording equipment. The recorder generates a strip chart that provides a permanent record of the flue gas opacity. If continuous monitoring is specified, periodic reports are generally required, and immediate notification of any excursion is usually mandated. Some agencies require periodic source tests and formal test reports. These requirements vary with the jurisdiction.

3.3 FEDERAL STANDARDS OF PERFORMANCE FOR NEW SOURCES

The Clean Air Act requires that EPA develop standards of performance for new stationary sources of significant air pollution. These standards, commonly known as NSPS's, are based on the best system of continuous emission reduction that has been adequately demonstrated, taking into account such nonair quality impacts as economics and energy. It should be noted that these regulations take the form of standards--not just emission limits. Thus, an NSPS regulation may require monitoring, process modification, or even specific emission reduction methods.

3.3.1 Particulate Emissions from Fuel-Burning Installations

There is no NSPS applicable to fuel-burning units with heat input rates less than 250 × 10^6 Btu/h. However, particulate emissions from units larger than 250 × 10^6 Btu/h--both utility and industrial boilers--are subject to the following NSPS limits:

Source category and affected facility	Emission limits
Electric Utility Steam Generating Units: >250 × 10^6 Btu/h input rate (size standard applies to each unit, not to aggregate; see § 60.330 et seq. for stationary gas turbines) for which construction is commenced after September 18, 1978. (Boilers and combined cycle gas turbines that exhaust >250 × 10^6 Btu/h to a steam generating unit.)	0.03 lb particulate matter/ million Btu heat input (40 CFR 60 Subpart Da)

Source category and affected facility	Emission limits
Fossil-fuel-fired Steam Generator: >250 × 10^6 Btu/h input rate (size standards applies to each unit, not to aggregate; applies to all units firing any form of fossil fuel or wood residue) for which construction is commenced after August 17, 1971	0.10 lb particulate matter/ million Btu heat input (40 CFR 60 Subpart D)

For electric utility steam generating units, the standard applies to any steam electric generating unit capable of combusting more than 250 × 10^6 Btu/h of heat input of fossil fuel and constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 megawatts of electrical output for sale to any utility distribution system. Fossil fuel by definition is natural gas, petroleum, coal, and any alternate form of fuel derived from any of these fuels for the purpose of creating useful heat. For nonutility boilers, the standard applies to each fossil fuel steam generating unit combusting more than 250 × 10^6 Btu/h and to each fossil fuel and wood residue steam generating unit capable of firing fossil fuel at a heat input of more than 250 × 10^6 Btu/h. For units capable of cofiring wood residue, the emission limit is based on the heat input of both the fossil fuel and the wood residue, as shown in the following examples:

	Example 1	Example 2	Example 3
Fossil fuel, Btu/h input	180	250	250
Wood residue, Btu/h input	100	0	60
Allowable emission rate lb/10^6 Btu	0.1	0.1	0.1
Allowable emissions for the stated input, lb/h	28	25	31

3.3.2 Visible Emissions--

Visible emissions from both utility and nonutility boilers subject to NSPS's are limited to 20 percent opacity except that for a period not to exceed six minutes per hour, a flue gas opacity of not more than 27 percent is permitted. The method used to measure this parameter is EPA Method 9 (40 CFR 60 Appendix A).

It should be noted (40 CFR 60.11) that owners or operators of utility and nonutility boilers may request the Administrator of EPA to determine opacity of the emissions from these boilers during the initial performance tests. If the Administrator finds that the source was in compliance with all applicable standards for which performance tests were conducted but during the time such performance tests were conducted the source failed to meet any applicable opacity standard, the Administrator shall notify and advise the source that the source may petition the Administrator to make appropriate adjustments to the opacity standard.

The Administrator will grant such a petition upon a demonstration that the source and the associated air pollution control equipment were operated and maintained in a manner to minimize the opacity of emissions during the performance tests; that the performance tests were performed under the proper conditions; and that the source and the control equipment were incapable of being adjusted or operated to meet the applicable opacity standard.

The Administrator will establish an opacity standard for the source at a level at which the source will be able to meet the opacity standard at all times during which the source is meeting the mass emission standard.

SECTION 4

BOILER EMISSIONS AND CONTROL TECHNIQUES

Boilers are usually sized according to heat input. They range from small skid-mounted package units to large steam electric generators that may consume more than 100 tons of coal per hour. Figure 4 shows typical size ranges for various boiler applications.

Particulate emissions are a function of fuel type as well as boiler design. Boilers are designed in many ways. Some are designed to burn pulverized coal or oil droplets in a suspended state; others such as stoker-fired units are designed to burn relatively large pieces of coal, wood, or bark on a grate. The design of the boiler and the fuel requirements are often based on total system size. Figure 5 presents the ranges of uncontrolled particulate emissions for fuel/boiler combinations.

4.1 CONTROL OF PARTICULATE EMISSIONS

Boiler flyash emissions are typically controlled by systems that incorporate high efficiency mechanical collectors, electrostatic precipitators, (ESP's), fabric filters, or wet scrubbers. Particulate matter controls are typically applied to coal-fired but not to oil-fired units because the uncontrolled emissions from oil-fired units are generally less than 0.05 lb/10^6 Btu. However, techniques are available for minimizing particulate matter emissions from oil-fired units. These techniques tend to fall into three major categories: operation and maintenance procedures; design changes to the burner and/or combustion chamber; and flue gas treatment.[57]

The most promising control techniques for industrial and utility oil-fired units are frequent cleaning of the fuel and the air-handling equipment; use of ESP's designed for oil-fired boilers; continuous flue gas measurements to maintain optimum combustion; and use of opacity monitors to warn the operator of abnormal combustion conditions.

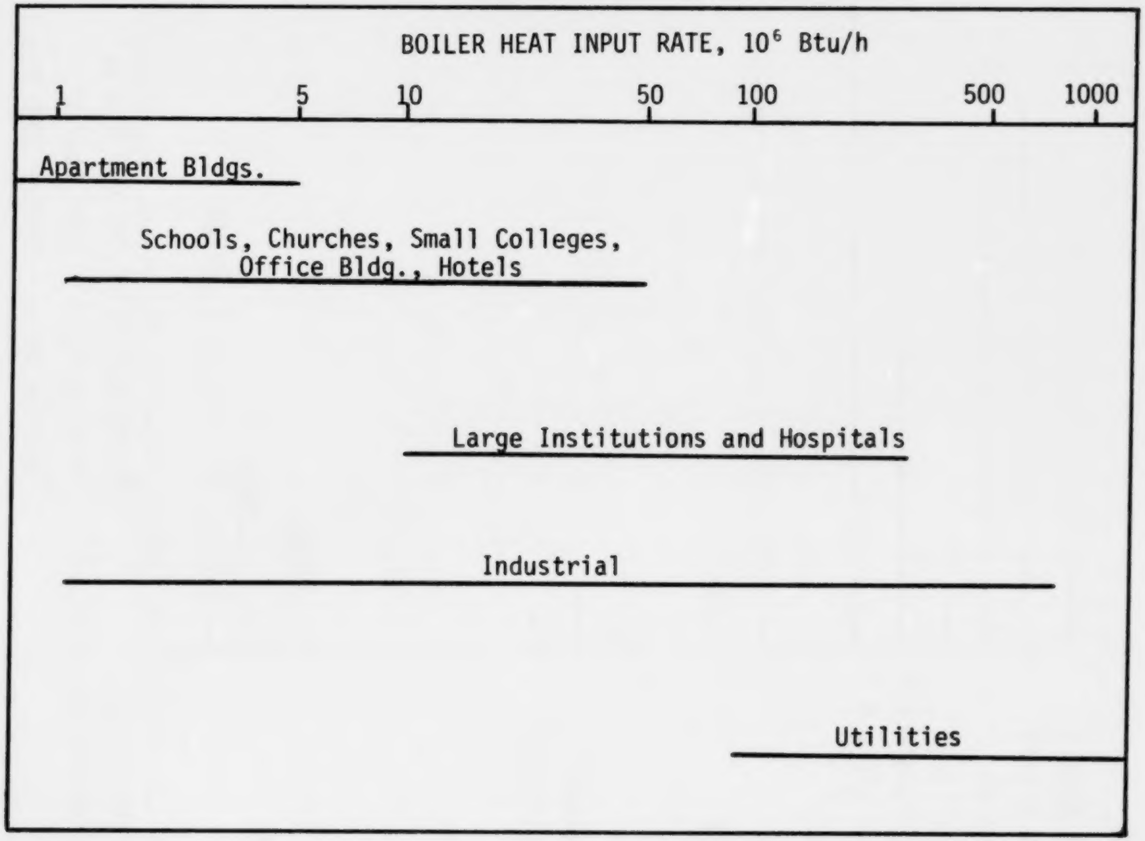
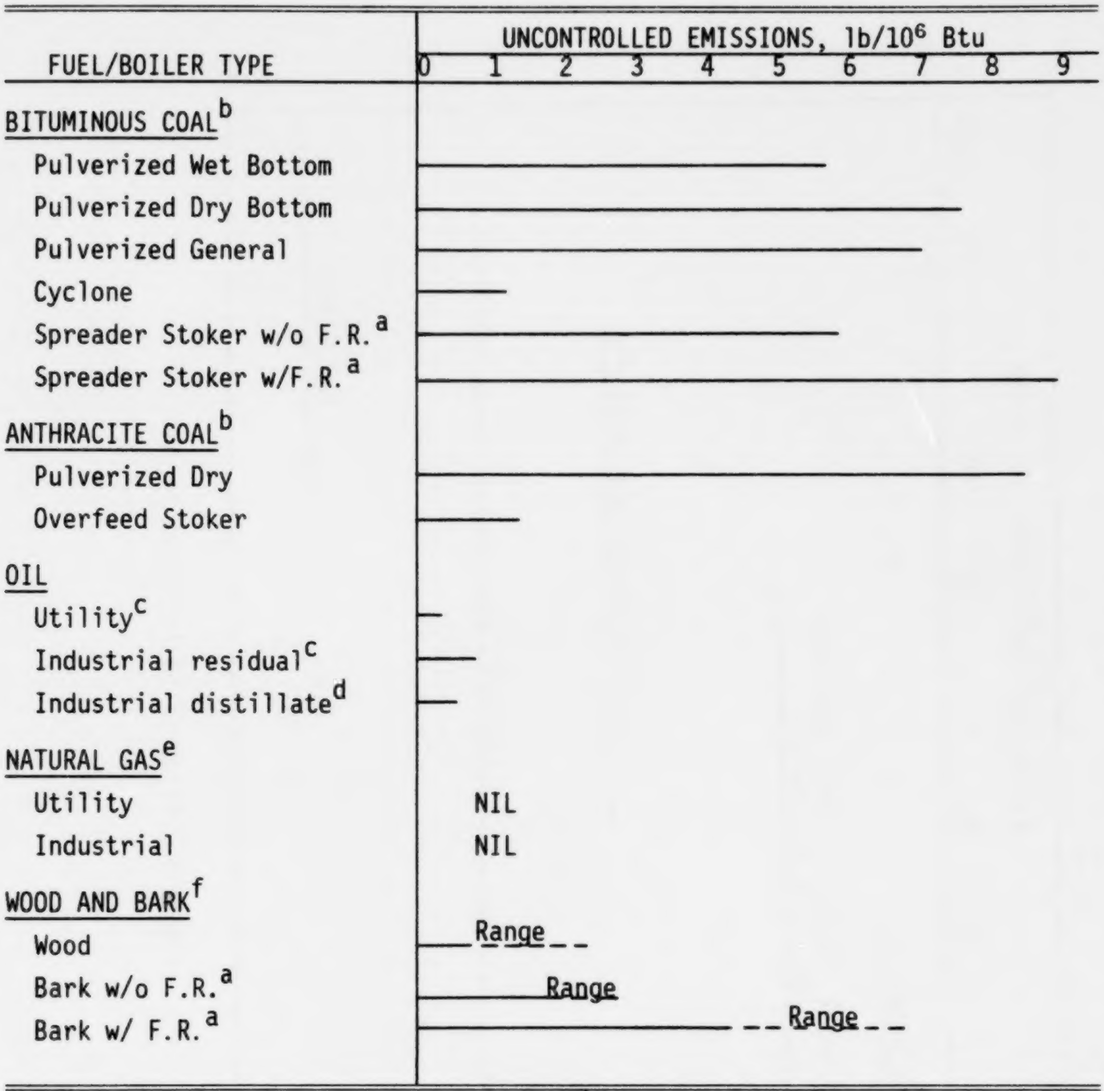


Figure 4. Range of boiler sizes by use.



[a] F.R. = Flyash reinjection.

[b] Heating Value - 24,000,000 Btu/ton, 10% ash content.

[c] Heating Value - 150,000 Btu/gal.

[d] Heating Value - 140,000 Btu/gal.

[e] Heating Value - 1000 Btu/ft^3.

[f] Heating Value - 4000 - 6000 Btu/lb.

Figure 5. Relative uncontrolled particulate emissions from various fuel/boiler combinations.

It has been suggested that emission reductions up to 30 percent could be achieved by reducing the interval between cleaning and inspections from 1 year to 3 months.[57] The ESP's are capable of reducing oil-fired particulate emissions by 50 to 99 percent. A reduction of over 90 percent can be obtained with correctly sized ESP's designed specifically for oil-fired units.[58]

The following discussions of control techniques are tailored to the control of particulate matter from coal-fired units because most particulate control efforts have centered on coal-fired units.

4.1.1 Mechanical Collectors

Systems based on inertial separation have been used for many years to control boiler emissions. Collection efficiencies vary with boiler type, method of combustion, properties of the fuel being burned, and size distribution of the flyash. Typical ranges for the collection efficiencies associated with mechanical collectors on various boiler or furnace types are shown below:[58]

Furnace type	Range of collection efficiency, %
Cyclone furnace	30 - 40
Pulverized coal	65 - 75
Spreader stoker	85 - 90
Other stokers	90 - 95

The major reason for the variation in the collection efficiency is the method of firing, which influences the uncontrolled emission rate and the size of the particles being emitted. When coal is thrown or blown into a furnace, combustion takes place in a suspension; as the pieces of coal burn, they become smaller so the probability of being exhausted in the stack gas increases. When coal is introduced tangentially (e.g., in a cyclone furnace), the burner acts as a mechanical separator and thus reduces emissions of larger particles.[59]

Most mechanical collectors are incapable of controlling emissions from coal-fired boilers sufficiently to meet any but the most lenient SIP requirements. Generally, the control efficiency for mechanical collectors begins to taper off at about 5 to 10 μm, and is almost zero for particles less than 1 to 2 μm, as illustrated in Figure 6. Typically mechanical collectors are capable of meeting limits from 0.3 to 0.6 $lb/10^6$ Btu, although a recent trend toward the use of a combination of mechanical collectors and fabric filters arranged in parallel have controlled emissions to well within many State allowable emission limits.

4.1.2 Electrostatic Precipitators

As the control requirements for particulate emissions from fuel combustion sources became more stringent, owners of large pulverized coal-fired boilers began to use ESP's. ESP's are reliable control devices that consistently remove more than 90 percent of the flyash in the exhaust gases. Since 1970, the minimum ESP collection efficiency has steadily increased due to the more stringent emission limits resulting from the development of the SIP's. Presently, the electric utility industry routinely removes more than 99 percent of boiler flyash.

In addition to more stringent limits on particulate emissions, State and local agencies have also imposed restrictions on the allowable sulfur oxide (SO_x) emissions from fuel combustion sources. In many cases to meet these SO_x limits, many fuel combustion sources have chosen to burn fuel with a low sulfur content. The lower sulfur content can raise the flyash resistivity in certain cases making it more difficult to achieve adequate power input, and thus effecting the overall ESP collection efficiency. For spreader stokers, the carbon content is usually very high which can lead to a very low flyash resistivity. Low resistivity flyash is easily reentrained and in many cases can lower the overall ESP collection efficiency.

Collection efficiency is ultimately a function of the ESP's plate area. As flyash resistivity increases, more plate area is needed. Figure 7 presents the relationship between collection efficiency and surface collection area (SCA) for various coal sulfur contents.[60]

ESP's are commonly used to control particulate emissions from boilers that fire coal, oil, and wood or bark. Typically, ESP's can be used to meet

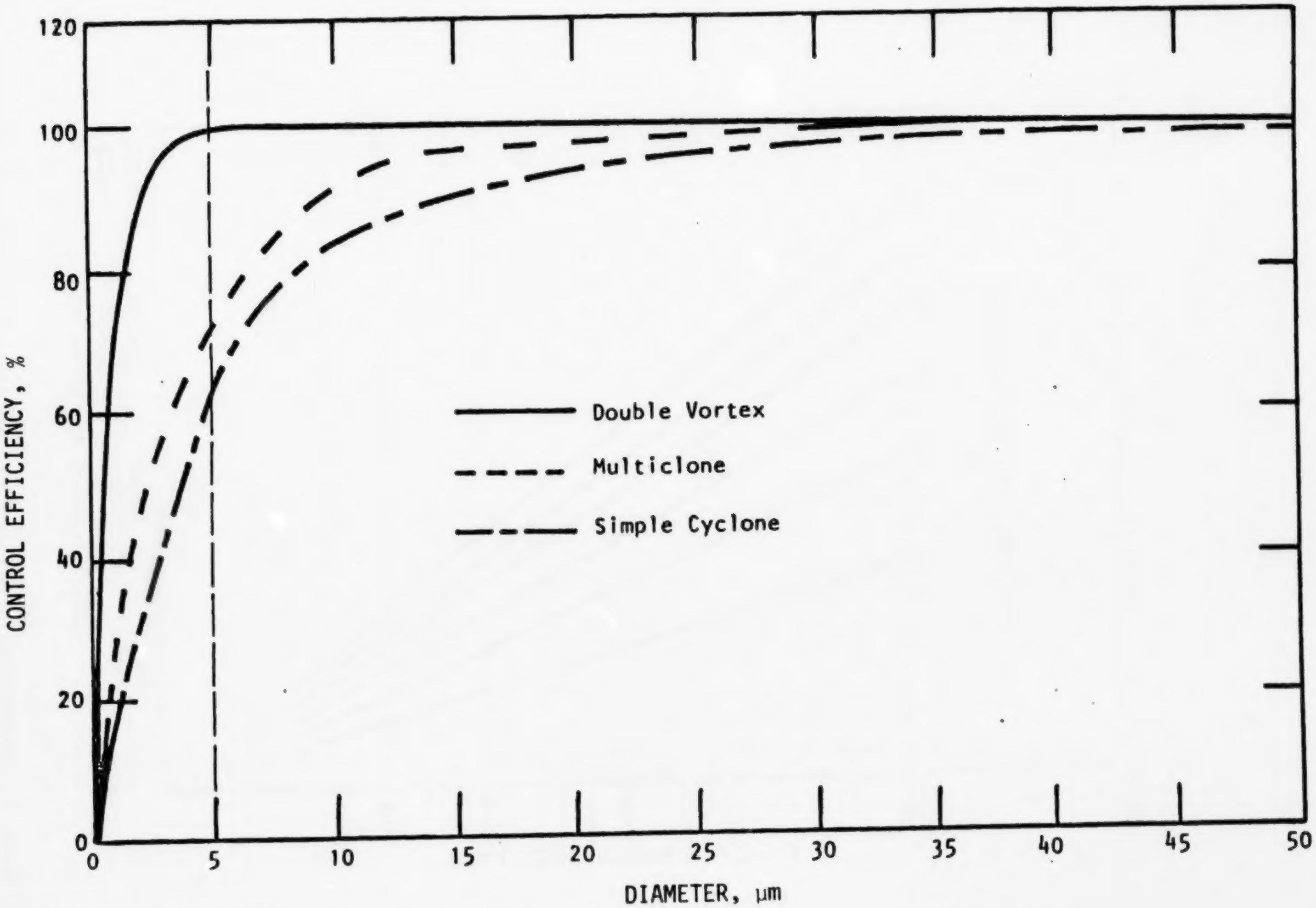


Figure 6. Control efficiency vs. particle size for mechanical collectors.

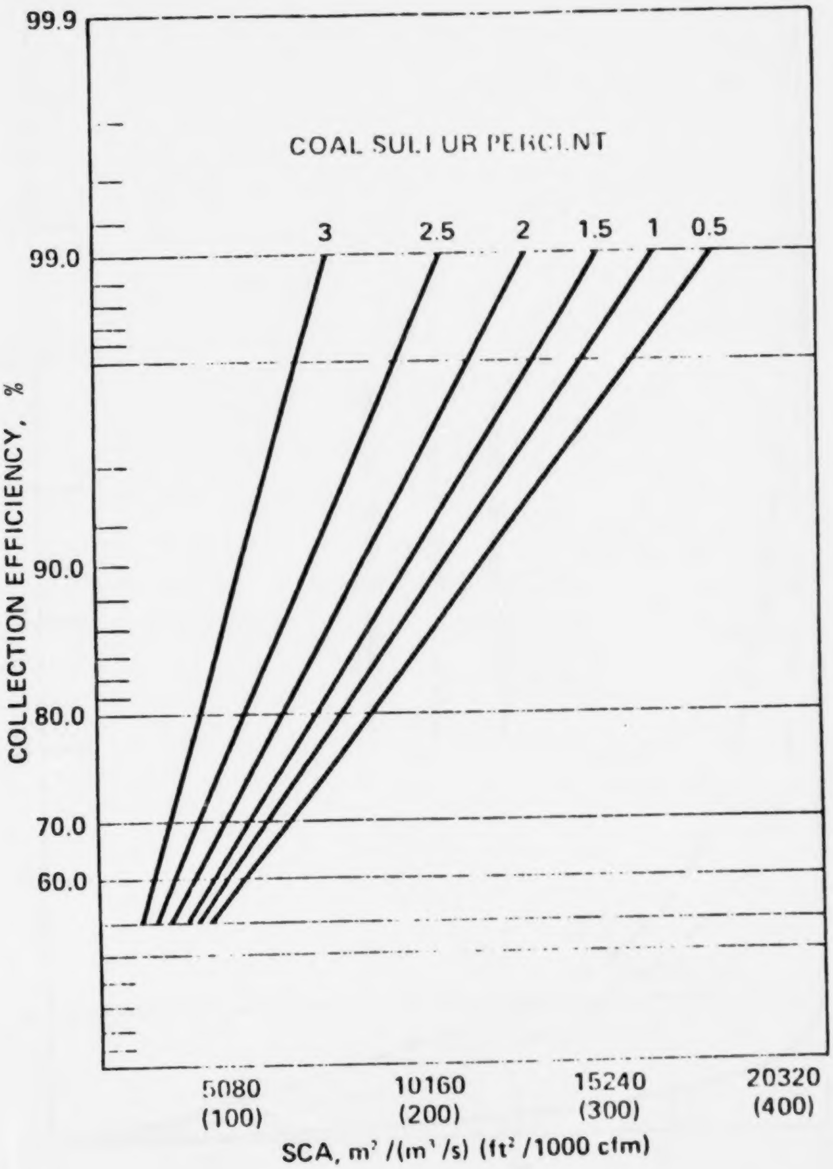


Figure 7. Relationship between collection efficiency and SCA for various coal sulfur contents.[60]

emission limits in the range of 0.03 to 0.1 lb/10^6 Btu. However, the overall limit that an ESP is capable of meeting depends on the type of fuel, the type of boiler, and the general operation and maintenance of the control equipment.

4.1.3 Fabric Filters

The application of fabric filters to fuel combustion sources is relatively recent. Although the basic particle collection mechanisms used in fabric filters are similar, the equipment geometry and the mode of fabric cleaning are quite different. There are two basic factors in fabric filter operation, particle capture and static pressure loss. The design of fabric filters involves a number of factors including process variables such as temperature, flyash particle size, and composition of the gas stream, along with their relationships with fabric selection, cake characteristics, pressure drop, cleaning cycle, and maintenance.

Unlike ESP's, fabric filters are sized solely on flue gas volume. The variance in flyash grain loading resulting from different furnace type does not generally affect fabric filter size. Fabric filters can achieve control efficiencies of 99 to 99.99 percent. They are generally used to control pulverized coal-fired units; however, they can be used to control oil-and wood-fired units as well as stoker coal-fired units when precautions are taken to prevent carryover of sparks to the fabric. Fabric filters can attain emission limits of 0.01 to 0.2 lb/10^6 Btu. The ability to achieve these limits depends in large part on the source's ability to operate and maintain the fabric filter.

4.1.4 Wet Scrubbers

Although a variety of wet scrubbers exist, they all have similar particle collection mechanisms. Inertial impaction and Brownain diffusion are dominant in most conventional scrubbers. Therefore, wet scrubbers generally exhibit strong particle-size-dependent performance, and are designed to collect particles smaller than 5 μm in diameter. Particle size, throat velocity, and the liquid-to-gas ratio all have a strong impact on the overall collection efficiency. Wet scrubbers generally achieve collection efficiencies of 95 to 98 percent, and can be used to meet emission limits of 0.1 to 0.4 lb/10^6 Btu.

4.2 RELATIONSHIP BETWEEN ALLOWABLE EMISSIONS AND OTHER PARAMETERS

As noted earlier, several factors affect the allowable particulate emissions from fuel combustion sources including boiler type, ash content, and overall efficiency of the control device. Figure 8 is a nomograph that can be used to quickly determine what the allowable emissions for a coal-fired boiler might be, given the boiler type, ash content, and overall collection efficiency. This nomograph can be used to roughly estimate the overall control efficiency needed for a source, given the allowable emissions in either lb/10^6 Btu, gr/scf, or lb/1000 lb dry flue gas, the boiler type, and the ash content. Additionally, the nomograph can be used to roughly estimate the Ringelmann number that would be associated with meeting a particular emission limit. It should be pointed out that there is no simple equation or method for relating mass emissions to visible emissions. The specific relationship between the mass emission limit and the visible emission limit can only be determined on a source-by-source basis by conducting a series of stack tests and visible emission observations under various source conditions.

Figure 8 is not an absolute estimator of allowable emissions and control efficiency. A number of simplifying assumptions regarding average heat content of the fuel,[58] percentage of excess air, and so forth, had to be made to develop such a nomograph. Therefore, it should not be used to determine the control efficiency needed for compliance with a particular regulation or to evaluate the ability of a particular piece of control equipment to meet a given mass or visible emission limit.

Figure 9 summarizes the particulate emission rates for a typical 100 × 10^6 Btu/h pulverized coal-fired boiler fueled with bituminous coal, assuming the application of various control devices.

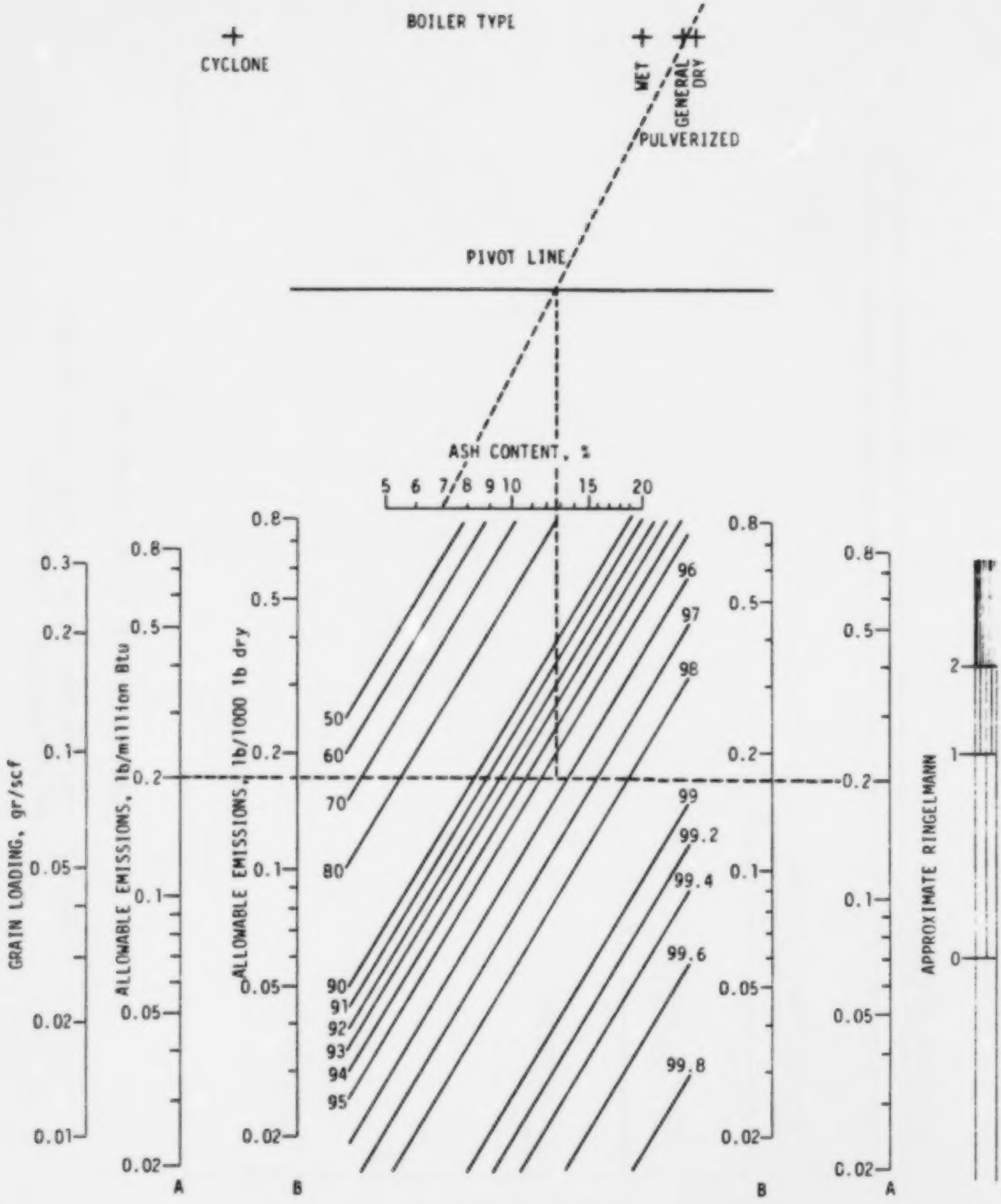


Figure 8. Nomograph for relating allowable emissions and overall control efficiency.

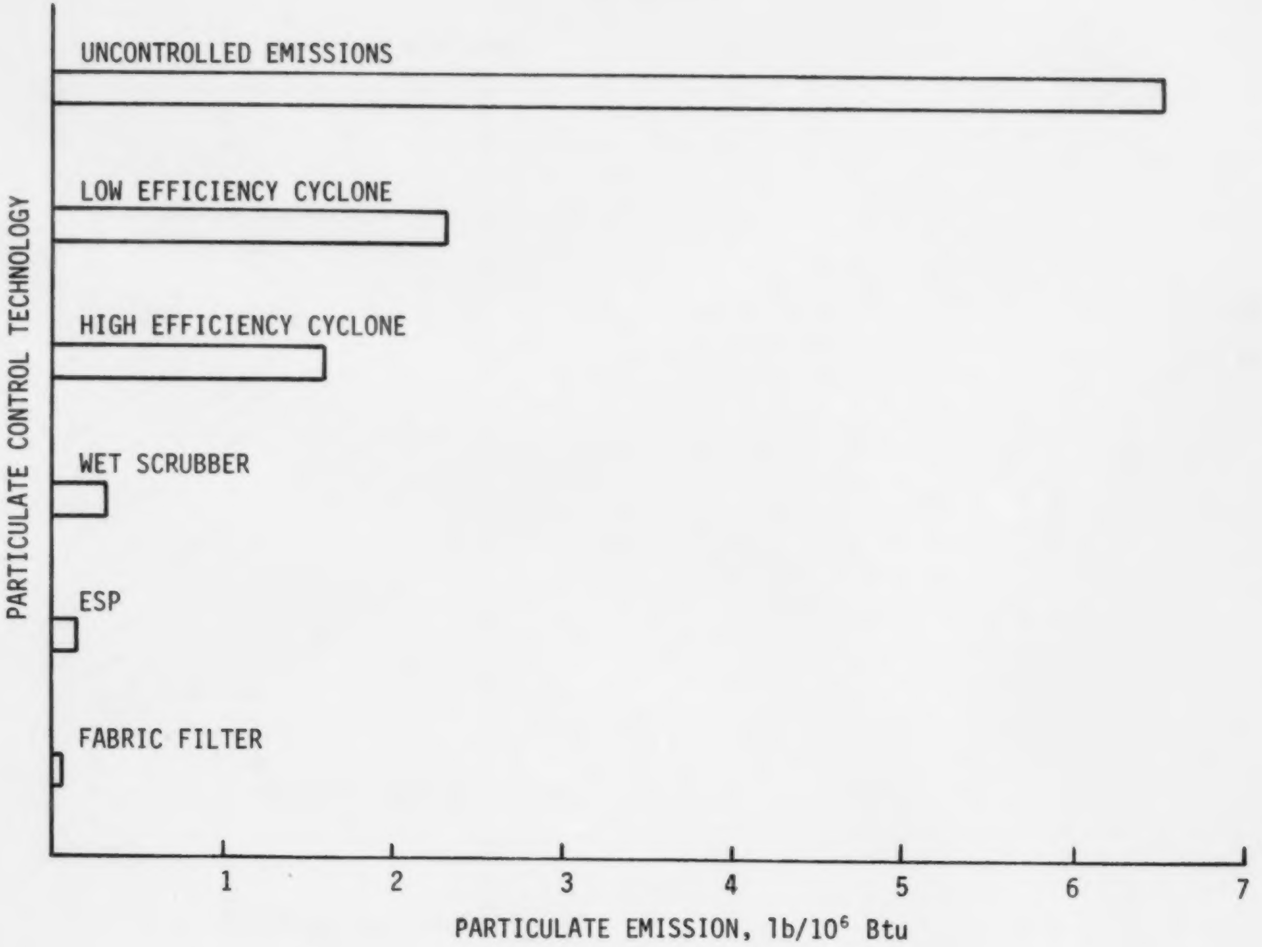


Figure 9. Particulate emission rates for typical pulverized coal-fired boiler.

SECTION 5

COMPILATION OF PARTICULATE MASS AND VISIBLE EMISSION LIMITS

This section compiles the mass and visible emission limits contained in the SIP's for the 50 States, the District of Columbia, and the four territories (American Samoa, Guam, Puerto Rico, and the Virgin Islands). This section also summarizes the requirements for continuous monitoring. Users are cautioned to contact the appropriate State and/or local air pollution control agency and EPA Regional Office to verify the specific emission limits applicable to an individual source.

5.1 SUMMARY OF MASS AND VISIBLE EMISSION REGULATIONS BY STATE OR TERRITORY

The following is a summary by State of the mass and visible emission limitations contained in the applicable SIP. Because an SIP may include State and local regulations, local regulations along with the State regulations have been included in the summary where they are part of the applicable SIP. The listing for each State is divided into two parts. Part A is a summary of the key elements of the mass emission requirements, and Part B is a summary of the key elements of the visible emission requirements. Part A explains how the total heat input is determined; how the regulation is applied (i.e., entire plant, individual unit, individual stack, etc.); the units of the regulation; the number of the reference figure that provides a graphical representation of the applicable regulation; and the measurement method. It also contains, in some cases, a series of footnotes that explain certain aspects of the regulations or any exceptions or exemptions.

About half of the States or territories determine heat input based on the aggregate heat content for all fuels burned. However, about 30 percent of the States or territories use the maximum design of the equipment to determine heat input. About 15 percent determine heat input by using the maximum of either the design or the amount of fuel burned. Less than half (40%) of the States or territories determine the heat content by considering all units; about 20 percent consider the individual units; and about 15 percent consider the individual stacks.

Seven States or territories do not specify (NS) whether the aggregate, the maximum design, or the maximum of design or amount of fuel burned is to be used in determining the total heat input. Ten States or territories do not specify whether the determination is to consider all units, just the individual units, or the individual stacks. However, in practice most of these States make the determination considering all units. In terms of overall applicability, over half of the States apply the regulations on an individual stack basis with the remainder of the States almost evenly divided between applying the regulations to the individual unit or the entire plant. Almost all States or territories expressed the units of the regulations as either lb/10^6 Btu or lb/h. There were, however, a few jurisdictions that expressed the units as lb/1000 lb stack gas or gr/scf.

Few States specify the method for determining compliance. In a few cases the ASME PTC-27 was the prescribed method. In other cases, the method to be used is one that is to be specified by the Agency director; however, no particular method was cited. Because all approved SIP's are enforceable by EPA, Method 5 (40 CFR 60, Appendix A) would be the method by which compliance would be determined in the absence of a specified State method. Therefore, where no reference method was specified, a blank was left in the appropriate column in Part A.

Part B summarizes the key elements of the visible emission requirements. Some States or territories specify both a Ringelmann number and an opacity limit. Others specify a Ringelmann and an equivalent opacity. Still others specify a Ringelmann number. The jurisdictions are almost evenly divided between those requiring 20 percent opacity (Ringelmann #1) and those requiring 40 percent opacity (Ringelmann #2) for existing sources.

Most States and local agencies allow visible emissions to exceed the prescribed standard for some finite period. However, six States have standards without an exception period. For the jurisdictions with exception periods, most agencies had an exemption for either 3 or 5 minutes in any one hour. There are, however, jurisdictions with exemption periods as short as 2 minutes or as long as 8 minutes in any one hour. Although some agencies have excursions associated with the prescribed standards, others prescribe an alternate visible emission limit as well as a period when this alternate standard can be exceeded. In addition, one State (Mississippi) specifies the number of minutes that the limit may be exceeded in any 24-h period and two others (Washington and New Hampshire) specify the total number of minutes in any 8-h period.

Although most States only specify a visible emission limit for existing sources, some States also specify a limit for new sources. In all cases, these new source limits were consistent with the NSPS requirements regarding visible emissions.

In all jurisdictions where Ringelmann numbers were used, the Ringelmann chart was the specified measurement method. However, none of the States that used opacity alone specified a particular measurement method. Because the Agencies did not specify a method for opacity and because an approved SIP is federally enforceable, the EPA Reference Method 9 would be used to certify compliance with the visible emission standard. No specific notations were made in the reference method column in Part B unless a method other than the Ringelmann chart or EPA Reference Method 9 was specified.

5.2 SUMMARY OF CONTINUOUS MONITORING REQUIREMENTS FOR OPACITY

In addition, to the specification of a measurement method, Part B identifies the requirements concerning continuous monitoring. A review of the State and local SIP regulations indicates that the State continuous monitoring requirements fall into four categories. The first includes those States that have incorporated the detailed continuous monitoring requirements into their SIP's. The second includes those states that have specific continuous monitoring requirements in their regulations, but do not have the specific performance specifications included as part of their SIP. The third includes those states that only specify a general requirement to conduct continuous monitoring. The fourth includes those states that do not specify any requirements for continuous monitoring.[61] To date, 22 States or territories do not have requirements for continuous monitoring; a few others specify that a source may be required to conduct monitoring; and only about 25 percent specifically require continuous monitoring of opacity for fuel combustion sources.

5.3 STATE AND TERRITORY SPECIFIC SUMMARIES

The following are state-by-state summaries of the mass emission rates and visible emission requirements for all 50 States, the District of Columbia, and the four territories. A complete copy of the regulations for each State is in Appendix B. Also, as noted earlier, the reference figures referred to in Part A are contained in Appendix A.

ALABAMA

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations							
	Aggregrate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10⁶ Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other	Reference figure	Measurement method	Footnotes
State	X					X				X									1. Applies to existing sources and all new sources in State regardless of location.
Class I Co.												X[1]					1-1	NS	
Class II Co.												X					1-2		
Huntsville												X					1-1		
Jefferson Co.												X					1-1		
Mobile Co.												X					1-1		

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources									
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other	Measurement method	Continuous monitoring requirement	Footnotes
State	1	20		3	60	3										X	
Huntsville	1	20		3	60	3											
Jefferson Co.	1	20		3	60	3											
Mobile Co.	1	20		3	60	3											

ALASKA

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on: Aggregate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Allowable emissions based on: Entire plant	Individual unit	Individual stack	Other	Units of the regulations: lb/10⁶ Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other	Reference figure	Measurement method	Footnotes
State							NS[4]		X						X[1,2]		NA		1. 0.5 gr/scf, 0.10 gr/scf sources in operation prior to July 1, 1972. 2. 0.15 gr/scf wood burning sources. 3. 0.3 gr/scf. 4. NS denotes not specified.
Cook Inlet															X[3]				

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources[2]							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other			
State		20	3														1. No greater than 40 minutes in any 24-h period. 2. Constructed after 8-17-71.
Cook Inlet	2	40	3					1	20	3							
Fairbanks	1			3		5[1]											

ARIZONA

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations					Reference figure	Measurement method	Footnotes
	Aggregrate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10^6 Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other			
State			X	X						X			X[1]				1-3		1. $\leq$ 4200 × 10^6 Btu/h $E = 1.02\ Q^{0.769}$ > 4200 × 10^6 Btu/h $E = 17.0\ Q^{0.432}$ 2. 10-4,000 × 10^6 Btu/h $Y = 1.02X^{-0.231}$ $\geq$ 4000 × 10^6 Btu/h $Y = 27X^{-0.568}$
Mohave Co.			X	X						X		X[2]					1-3	PTC-27	
Pima Co.			X	X						X			X[1]				1-3	MET. 5	
Pinal/Gila Co.			X	X						X		X[2]					1-3		
Yuma Co.			X	X						X		X[2]					1-3		

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other			
State	2	E[1]															1. E denotes enuivalent opacity.
Coconino Co.	2	E	3														
Maricopa Co.	2	E	3														
Mohave Co.	2	E	3														
Pima Co.	2	40		3	60	3											
Pinal/Gila Co	2	E															
Yuma Co.		20															

ARKANSAS

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations							Footnotes
	Aggregrate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10⁶ Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other	Reference figure	Measurement method	
State							NS[2]	X					X[1]				7-1		1. Uses general process weight rate regulation for solid fuel. Liquid and gaseous fuels are not covered under this requirement. 2. NS denotes not specified.

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources[1]							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other			
State	2	E[2]	5[3]					1	E		3		5[3]				1. Constructed after June 1, 1975. 2. E denotes equivalent opacity. 3. No more than 3 times in a 24-h period.

CALIFORNIA

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

	Total heat input based on:							Allowable emissions based on:				Units of the regulations							Footnotes
Political jurisdiction	Aggregrate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10^6 Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other	Reference figure	Measurement method	
South Coast							NS[4]			X			X[1]		X		2-1		1. 10 lb/h maximum.
San Diego							NS			X					X[2]				2. 0.1 gr/dscf.
Fresno							NS			X			X[1]		X[2]				3. 0.15 gr/dscf.
Sacramento							NS			X					X[2]				4. NS denotes not specified.
Bay Area							NS			X					X[3]				

PART B. VISIBLE EMISSION REGULATIONS

	Existing sources							New sources									Footnotes
	Requirement			Exception				Requirement			Exception						
Political jurisdiction	Ringelmann	Opacity	No more than —minutes in any 1 hour	Ringelmann	Opacity	No more than —minutes in any 1 hour	Other	Ringelmann	Opacity	No more than —minutes in any 1 hour	Ringelmann	Opacity	No more than —minutes in any 1 hour	Other	Measurement method	Continuous monitoring requirement	
State																X	1. LA, Orange, West-central area of Riverside County.
South Coast	1[1] 2[2]	E[3] E	3 3														2. Rest of Riverside County. 3. E denotes equivalent opacity.
San Diego	1	E	3														
Fresno	1	E	3														
Sacramento	1	E	3														
Bay Area	1	E	3														

COLORADO

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations							Footnotes
	Aggregrate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10^6 Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other	Reference figure	Measurement method	
State	X				X					X		X					II-4		

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than — minutes in any 1 hour	Ringelmann	Opacity	No more than — minutes in any 1 hour	Other	Ringelmann	Opacity	No more than — minutes in any 1 hour	Ringelmann	Opacity	No more than — minutes in any 1 hour	Other			
State		20			40	3			20			40	3				

CONNECTICUT

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations							Footnotes
	Aggregrate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10^6 Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other	Reference figure	Measurement method	
State			X				NS[1]	X				X[2]							1. NS denotes not specified. 2. 0.20 lb/10^6 Btu, existing 0.10 lb/10^6 Btu, new (constructed after 5-23-72)

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than — minutes in any 1 hour	Ringelmann	Opacity	No more than — minutes in any 1 hour	Other	Ringelmann	Opacity	No more than — minutes in any 1 hour	Ringelmann	Opacity	No more than — minutes in any 1 hour	Other			
State	1	20		2	40	5										X[1]	1. General opacity monitoring requirements for: a. coal burning b. liquid or solid > 5 x 10^6 Btu/h c. incinerator > 2,000 lb/h d. process sources > 5 lb/h e. No. 6 residual oil burners

DELAWARE

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations							Footnotes
	Aggregrate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10⁶ Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other	Reference figure	Measurement method	
State		X[1]			X				X			X[2]							1. Maximum of manufacturer's guaranteed maximum input or Department's calculated input. 2. 0.30 lb/10^6 Btu, maximum 2-h average.

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other			
State	1	20	3[1]													X	1. 15 minutes in any 24-h period.

DISTRICT OF COLUMBIA

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations					Reference figure	Measurement method	Footnotes
	Aggregate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10^6 Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other			
District	X						NS[1]			X		X[2]					1-5		1. NS denotes not specified. 2. $Y = 0.17455X^{-0.23522}$ can not exceed 0.13 lb/10^6 Btu or be required to emit <0.02 lb/10^6 Btu.

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other			
District	2	40	12[1]														1. 12 minutes in any 24-h period.

FLORIDA

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations					Reference figure	Measurement method	Footnotes
	Aggregate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10⁶ Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other			
State	X			X					X			X[1]							1. 0.10 lb/10⁶ Btu, all units > 250 x 10⁶ Btu/h (maximum 2-h average) 20% opacity, all units < 250 x 10⁶ Btu/h.

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than — minutes in any 1 hour	Ringelmann	Opacity	No more than — minutes in any 1 hour	Other	Ringelmann	Opacity	No more than — minutes in any 1 hour	Ringelmann	Opacity	No more than — minutes in any 1 hour	Other			
State	2[1]	40						1	20		2	40	2			X[2]	1. After July 1, 1975, all sources must meet #1 Ringelmann and 20% opacity. 2. General SO_2 monitoring provision for fossil fuel fired steam generators only.

GEORGIA

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations							Footnotes
	Aggregrate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10⁶ Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other	Reference figure	Measurement method	
State	X				X				X			X					1-6[1] 1-7[2]		1. Existing sources < 10 x 10^6 Btu/h 0.07 lb/10^6 Btu/h 10 - 2000 x 10^6 Btu/h $Y = 0.7(\frac{10}{X})^{0.202}$ >2000 x 10^6 Btu/h 0.24 lb/10^6 Btu 2. New sources (constructed after 1-1-72) < 10 x 10^6 Btu/h 0.5 lb/10^6 Btu/h 10 - 250 x 10^6 Btu/h $Y = 0.5(\frac{10}{X})^{0.5}$ >250 x 10^6 Btu/h 0.10 lb/10^6 Btu

(continued)

GEORGIA (continued)

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources[2]							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than — minutes in any 1 hour	Ringelmann	Opacity	No more than — minutes in any 1 hour	Other	Ringelmann	Opacity	No more than — minutes in any 1 hour	Ringelmann	Opacity	No more than — minutes in any 1 hour	Other			
State	2	40		3	60	3[1]		1	20		2	40	2				1. In any half-hour period. 2. Constructed after 1-1-72.

HAWAII

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations					Reference figure	Measurement method	Footnotes
	Aggregate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10⁶ Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other			
State							NS[1]		X							X[2]			1. NS denotes not specified. 2. New and existing bigasse-burning boiler 0.4 lbs/100 lb bigasse burned.

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources[1]							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than — minutes in any 1 hour	Ringelmann	Opacity	No more than — minutes in any 1 hour	Other	Ringelmann	Opacity	No more than — minutes in any 1 hour	Ringelmann	Opacity	No more than — minutes in any 1 hour	Other			
State	2	40		3	60	3[2]		1	20		3	60	3[2]				1. Constructed after December 31, 1973. 2. During equipment breakdown or new fire building only.

IDAHO

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations					Reference figure	Measurement method	Footnotes
	Aggregrate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10^6 Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other			
State	X					X					X[1]	X					1-8		1. 2 or more units through one stack, use combined heat input of all units. 1 unit through 2 or more stacks, allowable emissions for all units combined should not exceed allowable for same unit with one stack.

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources[1]							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other			
State	2	40	3					1	20	3							1. Did not specify a date for new sources.

ILLINOIS

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

	Total heat input based on:							Allowable emissions based on:				Units of the regulations						
Political jurisdiction	Aggregate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10^6 Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other	Reference figure	Measurement method
State	X					X				X							1-9	X^1
Chicago Major-Metro. Area												X^2						
Outside Major-Metro. Chicago Area												X^3						
Controlled Sources												X^4						
Cook Co.											X^5							

Footnotes

1. ASME power test codes.
2. Existing and new

   Solid - 0.1 lb/mmBtu
   Liquid - 0.1 lb/mmBtu
   Combination - $S_s H_s + 0.10\ H_L$
   where:
   S_s = solid fuel type particulate emission standard, lb/10^6 Btu
   H_s = actual heat input from solid fuel, 10^6 Btu/h
   H_L = actual heat input from liquid fuel.

3. Existing

   Solid

$Q < 10 \times 10^6$ Btu/h	1.0 lb/10^6
$10 < Q < 250 \times 10^6$ Btu/h	$E = 5.18Q^{-0.7E}$
$Q \geq 250 \times 10^6$ Btu/h	0.1 lb/10^6 Btu

   Liquid - see 2
   Combination - see 2

4. The emission source must have an emission rate based on original design or equipment performance test conditions, whichever is stricter, which is < 0.2 lb/10^6 Btu and the emission control must not be allowed to degrade > 0.05 lb/10^6 Btu.

5. PM emissions are limited to ≤ 10% by weight of particles > 44 micron. Calculations are also made for the various control zones to determine the net rate of emission in lb/acre/h from each emission source. The limit for the zones is as follows:

   Zone 1 - 1.0 lb/acre/h
   Zone 2 - 3.0 lb/acre/h
   Zone 3 - 8.0 lb/acre/h

(continued)

ILLINOIS (continued)

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources[3]							New sources[3]							Measurement method	Continuous monitoring requirement
	Requirement			Exception				Requirement			Exception					
	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other		
State		30			30-60	8			20[1]			20-40	3		x[4]	X
									30[2]			30-60	8			
Cook County	2	40					x[5]									

Footnotes

1. Source with actual heat input > 250 x 10^6 Btu/h.
2. New sources < 250 x 10^6 Btu/h.
3. VE limitations shall not apply if emission source was in compliance with the applicable mass emission limitation.
4. a) visual observation
   b) use of calibrated smoke evaluation device
   c) continuous monitors.
5. Cook County uses a measurement of smoke units; in Zone 1, 20 smoke units are permitted and 35 units, once during any 6-h period for each stack when blowing soot or cleaning fines; in Zone 2, 50 units are permitted with an exemption as above of 62 units; and in Zone 3, up to 76 units/h per stack is permitted with an exemption as above of 92 smoke units.

INDIANA

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations							Footnotes
	Aggregrate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10⁶ Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other	Reference figure	Measurement method	
All areas except Lake and Porter Co. and Metro. Indianapolis Intrastate AQCR		X		X				X				x^1					3-1		1. Emission limited by ASME Standard No. APS-1 with maximum allowable of 0.8 lb/10^6 Btu for existing sources and 0.6 lb/10^6 Btu for new sources $\leq$ 250 x 10^6 Btu/h (constructed after 9-14-72).
Lake and Porter Co. and Metro-Indianapolis Intrastate AQCR												x^2					1-10		2. Emission limit = 0.87 $Q^{-0.16}$ lb/10^6 Btu and 0.10 lb/10^6 Btu for new sources in excess of 250 x 10^6 Btu/h.

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other			
State	2	40			60		x^1	2	40			60		x^1		X	1. Opacity up to 60% is permitted while building a fire for a period not to exceed 10 min in any 24-h or blowing tubes or cleaning for a period not to exceed 5 min in any 60 min but not permitted more than 6 times in any 24-h.

IOWA

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations					Reference figure	Measurement method	Footnotes
	Aggregrate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10^6 Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other			
State	X					X				X							3-2		1. Existing and new ASME Standard APS-1, Fig. 3-1, with a maximum allowable rate of 0.6 lb/10^6 Btu.
Inside SMSA												X[1]							
Outside SMSA												X[2]					3-1		2. ASME Standard APS-2, Fig. 3-2, with a maximum allowable rate of 0.8 for existing sources and 0.6 for new sources. **Note**: Use Eq. 15 with C max = 50 $\mu g/m^3$ for stacks $\geq 4{,}000 \times 10^6$ Btu/h, a = 1.0; for stacks $< 4{,}000 \times 10^6$ Btu/h, a < 1.0 as appropriate.

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other			
State	2	40				6[1]										X[2]	1. Building or cleaning a fire or blowing tubes and flues. 2. Opacity for coal and coal-gas fired steam generating units.

KANSAS

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations							Footnotes
	Aggregrate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10⁶ Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other	Reference figure	Measurement method	
State			X	X				X				X[1]					1-11		1.

1.

Total Input 10^6 Btu/h	Allowable lb/h/10^6 Btu
<10	0.60
50	0.41
100	0.35
500	0.24
700	0.22
1,000	0.21
2,000	0.17
5,000	0.14
7,500	0.13
>10,000	0.12

For Interpolation:

$E = 1.026Q^{-0.233}$

Note: Any existing coal burning unit operating < 100 h in a yr may emit no more than 1.2 lb/10^6 Btu pending dept. approval and if average annual emissions do not exceed limit for the plant.

(continued)

KANSAS (continued)

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources[1]							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other			
State		40							20								1. Date not specified.

KENTUCKY

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

	Total heat input based on:							Allowable emissions based on:				Units of the regulations							Footnotes
Political jurisdiction	Aggregrate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10⁶ Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other	Reference figure	Measurement method	
State[1]		X		X					X			X[2]					1-12 1-13 1-14		1. Sources > 1 x 10^6 Btu/h or > 50 x 10^6 Btu/h if natural gas, distillate fuel oil, or a combination is burned. 2. New sources (constructed after 4-9-72) - $E = 0.9634Q^{-0.2356}$ Existing sources - Priority I $E = 0.9634Q^{-0.2356}$ Priority II $E = 1.2825Q^{-0.2330}$ Priority III $E = 1.3152Q^{-0.2159}$ where: $10 \le Q \le 10{,}000 \times 10^6$ Btu/h

PART B. VISIBLE EMISSION REGULATIONS

	Existing sources							New sources									Footnotes
	Requirement			Exception				Requirement			Exception						
Political jurisdiction	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other	Measurement method	Continuous monitoring requirement	
State[1]									20			40	2			X[2]	1. Sources > 1 x 10^6 Btu/h or > 50 x 10^6 Btu/h if natural gas, distillate fuel oil, or a combination is burned. 2. No requirements for fluidized bed catalyst regenerator. In general not as specific as Appendix P of part 51.
Priority I		20			40	2											
Priority II or III		40			60	6											

LOUISIANA

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations					Reference figure	Measurement method	Footnotes
	Aggregate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	$lb/10^6$ Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other			
State							NS[2]	X				X[1]							1. 0.6 $lbs/10^6$ Btu. 2. NS denotes not specified.

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources								New sources								Measurement method	Continuous moni- toring requirement	Footnotes
	Requirement			Exception					Requirement			Exception							
	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other		Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other				
State	1	20	4															X	

MAINE

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations							Footnotes
	Aggregrate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10⁶ Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other	Reference figure	Measurement method	
State[1]			X			X				X		X					1-19	X[2]	1. All equipment ≥ 3 x 10^6 Btu/h regardless of fuel type and all fuel burning sources > 10 x 10^6 Btu/h. 2. EPA test method 1 and 5.

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than ___ minutes in any 1 hour	Ringelmann	Opacity	No more than ___ minutes in any 1 hour	Other	Ringelmann	Opacity	No more than ___ minutes in any 1 hour	Ringelmann	Opacity	No more than ___ minutes in any 1 hour	Other			
State	2	40	5[1]														1. 15 min in any 3-h period.

MARYLAND

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations					Reference figure	Measurement method	Footnotes
	Aggregate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	$lb/10^6$ Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other			
Garrett, Allegheny, Washington, Frederick, Calvert, Charles, St. Mary's, Caroline, Cecil, Dorchester, Kent, Somerset, Talbot, Wicomico, Worchester Counties		X			X					X		x^2			x^1		1-39 1-40		1. New sources - use Figure 1-39 (constructed after 1-17-72) 2. Existing $< 10 \times 10^6$ Btu/h $E = 0.60$ $lb/10^6$ Btu $10 < Q < 10,000 \times 10^6$ Figure 1-40 $> 10,000 \times 10^6$ Btu/h $E = 0.12$ $lb/10^6$ Btu 3. Adjust to 50% excess air.
Baltimore City, Anne Arundel, Baltimore, Carroll, Hartford, Howard, Montgomery, Prince George's															x^3				

(continued)

MARYLAND (continued)

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources[1]							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other			
State															X[2]		1. Constructed after 1-17-72. 2. Method 9.
Garrett, Allegheny, Washington, Frederick Co.	1	20		2	40	6			0		2	40	6				
Baltimore City, Anne Arundel, Baltimore, Carroll, Hartford, Howard, Montgomery, Prince George's Co.		0		2	40	6			0		2	40	6				
Calvert, Charles, St. Mary's, Caroline, Cecil, Dorchester, Kent, Queen Anne's.																	
Somerset, Talbot, Wiconico, Worchester	1	20		2	40	6			0		2	40	6				

MASSACHUSETTS

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations							Footnotes
	Aggregrate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10^6 Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other	Reference figure	Measurement method	
State	X			X						X		X^1						X^2	1. Facility size, 10^6 Btu/h — Emission limitation, lb/10^6 Btu NEW (constructed after 8-17-71) 3-250 — 0.10 > 250 — 0.05 (0.10 if SO_2 control device) EXISTING 3-250 — 0.15 > 250 — 0.15 Existing in critical area of concern 3-250 — 0.12 > 250 — 0.12 2. EPA Method 5.

(continued)

MASSACHUSETTS (continued)

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources							Measurement method	Continuous moni-toring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other			
State	1			2		6										X^1	1. General opacity requirement for selected fossil fuel sources - oil or solid fuel and > 10 x 10^6 Btu/h.
		20			40	2											

MICHIGAN

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations					Reference figure	Measurement method	Footnotes
	Aggregrate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10^6 Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other			
State		X			X				X					X			4-1[1] 4-2[2]		1. Pulverized coal (includes cyclone furnace). 2. Other modes of firing.
Wayne County														X					

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than — minutes in any 1 hour	Ringelmann	Opacity	No more than — minutes in any 1 hour	Other	Ringelmann	Opacity	No more than — minutes in any 1 hour	Ringelmann	Opacity	No more than — minutes in any 1 hour	Other			
State	2		3[1]	3		3[2]											1. 3 minutes in any 30 minute period. 2. Shall not be exceeded on more than 3 occasions during any 24-h period.
Wayne County	1.5	30	3[1]														

MINNESOTA

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations							Footnotes
	Aggregrate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10^6 Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other	Reference figure	Measurement method	
State		X			X					X		X^{1,2}						APS 1	1. New sources and sources located within Minneapolis-St. Paul AQCR and the city of Duluth. 0.4 lb/10^6 Btu 2. Existing sources and sources outside above areas. 0.6 lb/10^6 Btu

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other			
State	3 2-3 1-2	60 40-60 20-40	 4 4[1]					1	20							X[2]	1. In any 30 minute period. 2. No requirements for existing fossil fuel fired steam generators.

MISSISSIPPI

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations					Reference figure	Measurement method	Footnotes
	Aggregate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10⁶ Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other			
State	X			X				X				X					1-10[1]		1. Combination boilers - up to 0.30 grains/scf.

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other			
State	2	40	15[1]	3		10[2]											1. No more than 3 periods in any 24-h. 2. Aggregate duration of emissions due to soot blowing during any 24-h period does not exceed 10 minutes per billion Btu gross heating value of fuel in any one hour.

MISSOURI

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations					Reference figure	Measurement method
	Aggregate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	$lb/10^6$ Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other		
State			X	X						X		X[1]					1-16	PTC-27
Independence			X	X						X		X[3]					1-17	PTC-27
Kansas City			X	X						X		X[3]						PTC-27
Springfield-Greene Co.			X	X						X		X[2]						PTC-27
St. Louis			X							X		X[3,4]					1-16	PTC-27

Footnotes

1. Existing -

   Log $y = -0.23299$ Log $X + 1.4091$
   $10 < x < 10{,}000$
   $\leq 10 \times 10^6$ Btu/h = 0.60 lb/10^6 Btu
   $\geq 10{,}000 \times 10^6 = 0.18$ lb/10^6 Btu

   New (constructed after 4-3-71) -

   $\leq 10 \times 10^6 = 0.60$ lb/10^6 Btu
   $\geq 2{,}000 \times 10^6 = 0.10$ lb/10^6 Btu
   Log $y = -0.3882$ log $X + 2.1454$
   $10 < x < 2{,}000 \times 10^6$

2. $10 < x < 10{,}000 \times 10^6$

   Log $y = 0.2330$ Log $X - 2.0111$
   $< 10 \times 10^6 = 0.60$ lb/10^6 Btu
   $\geq 10{,}000 \times 10^6 = 0.12$ lb/10^6 Btu

3. Existing

   $E = 1.09\ Q^{-0.259}$
   $< 10 \times 10^6 = 0.6$ lb/10^6 Btu
   $\geq 5{,}000 \times 10^6 = 0.12$ lb/10^6 Btu

   New (constructed after 2-15-79)

   $E = 0.8\ Q^{-0.301}$
   $< 10 \times 10^6 = 0.4$ lb/10^6 Btu
   $\geq 1{,}000 \times 10^6 = 0.1$ lb/10^6 Btu

4. Also regulations based on stack height.

(continued)

MISSOURI (continued)

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources[1]									Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other	Measurement method	Continuous monitoring requirement	
State	2			3		6		1			3		6			X	1. Constructed after 4-3-71 except St. Louis where new is constructed after 2-15-79.
Independence	1			3		6		1			3		6				
Kansas City	1			3		6		1			3		6				
Springfield-Greene County	2			3		6		1			3		6				
St. Louis	2			2		6		1			2		6				

MONTANA

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations							Footnotes
	Aggregrate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10^6 Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other	Reference figure	Measurement method	
State	X					X				X		X					1-10[1] 1-18[2]		1. Existing. 2. New (constructed after 11-23-68).

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources[1]							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than — minutes in any 1 hour	Ringelmann	Opacity	No more than — minutes in any 1 hour	Other	Ringelmann	Opacity	No more than — minutes in any 1 hour	Ringelmann	Opacity	No more than — minutes in any 1 hour	Other			
State	2			3		4			20			60	4				1. Constructed after 11-23-68.

NEBRASKA

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations					Reference figure	Measurement method	Footnotes
	Aggregate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10^6 Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other			
State	X		X	X				X				X[1]					1-19		1. <10×10^6 Btu/h 0.60 lb/10^6 Btu >3800×10^6 Btu/h 0.15 lb/10^6 Btu $Y = \frac{1.026}{X^{.233}}$ Y = allowable emissions X = total heat input
Omaha							NS			X		X					1-18	PTC-27	
Lincoln							NS				NS	X					1-20		

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources[1]							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than — minutes in any 1 hour	Ringelmann	Opacity	No more than — minutes in any 1 hour	Other	Ringelmann	Opacity	No more than — minutes in any 1 hour	Ringelmann	Opacity	No more than — minutes in any 1 hour	Other			
State	1	20														X[2]	
Omaha	2		3[3]					1									
Lincoln[4]	2			2		3		1			3		3				

1. Constructed after 8-17-71.
2. Fossil Fuel-Fired Steam Generators only.
3. No more than 3 occasions in any 24-h period.
4. No limit on opacity for units < 0.10 lb/1000 lbs flue gas.

NEVADA

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations					Reference figure	Measurement method	Footnotes
	Aggregate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10^6 Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other			
State (except Reno, Sparks, Washoe Co.)			X	X				X				X[1]					1-3		1. $\leq 10 \times 10^6$ Btu/h $E = 0.6$ lb/10^6 Btu $10 < Q < 4000 \times 10^6$ Btu/h $E = 1.02Q^{-0.231}$ $\geq 4{,}000 \times 10^6$ Btu/h $E = 17.0\ Q^{-0.568}$ 2. 0.15 gr/scf
Reno, Sparks, Washoe Counties															X[2]				

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other			
State except Clark, Reno, Sparks, Washoe Co.		20	3													X	
Clark, Reno, Sparks, Washoe Co.	1		3														

NEW HAMPSHIRE

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations							Footnotes
	Aggregate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10^6 Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other	Reference figure	Measurement method	
State	X					X				X		X^{1,2}					1-10^{1} 1-21^{2}		1. Existing $Q \leq 10 \times 10^6$ Btu/h $E = 0.60$ lb/10^6 Btu $10 < Q < 10{,}000 \times 10^6$ Btu/h $E = 0.8803Q^{-0.1665}$ $Q \geq 10{,}000 \times 10^6$ Btu/h $E = 0.19$ lb/10^6 Btu 2. New (constructed after 2-18-72) $Q \leq 10 \times 10^6$ Btu/h $E = 0.60$ lb/10^6 Btu $10 < Q \leq 250 \times 10^6$ Btu/h $E = 1.0286Q^{-0.2341}$ $Q > 250 \times 10^6$ Btu/h $E = 0.10$ lb/10^6 Btu

(continued)

NEW HAMPSHIRE (continued)

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources[1]							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other			
State -																	1. Constructed after 2-18-72. 2. Installations equipned with automatic soot blowers will be permitted to exceed No. 2 for a period not to exceed 60 min in any 8-h period.
sources $< 250 \times 10^6$ Btu/h	2	40			40	6[2]		1	20				6[2]				
sources $> 250 \times 10^6$ Btu/h		20			40	2			20			40	2				

NEW JERSEY

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations					Reference figure	Measurement method	Footnotes
	Aggregrate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10^6 Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other			
State	X					X				X			X[1]				5-1		1.

Heat input rate, 10^6 Btu/h	Maximum allowable emission rate, lb/h
1	0.6
10	6.0
100	15.0
1,000	100.0
10,000	1,000.0

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other			
State[1,2]	1	20				3[3]											1. Sources > 200 x 10^6 Btu/h and stacks with cross sectional dimension $\geq$ 60 in. 2. Sources < 200 x 10^6 Btu/h. No visible emissions. 3. 3 min in any one-half hour period.

NEW MEXICO

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations					Reference figure	Measurement method	Footnotes
	Aggregrate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10^6 Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other			
State	X				X				X			X[1]					1-22[2] 1-23[3]	PTC-27	1. Coal burning - 0.05 lb/10^6 Btu Oil burning - > 10^{12} Btu/yr/unit E < 0.005 lb/10^6 Btu 2. Existing. 3. New (12-31-71)

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other			
State (except Albuquerque-Bernalillo Co)	1		X[1]														1. No more than 1 min in any 30 min.
Albuquerque-Bernalillo Co.	1	20															

NEW YORK

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations							Footnotes
	Aggregate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	$lb/10^6$ Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other	Reference figure	Measurement method	
State	X					X				X		X[1]					1-35 1-36		1. Solid fuel-burning units spreader stocker, $Q \le 300$ 0.60 $lb/10^6$ Btu other units, $Q \le 300$ Q, 10^6 Btu/h — E, $lb/10^6$ Btu 1-100 — 0.6 200 — 0.45 300 — 0.30 Units > 300 Btu/h $Q \le 10$ 0.6 $lb/10^6$ Btu $10 < Q < 10,000$ $E = 1.02\ Q^{-0.219}$ Oil fired or coal > 250 x 10^6 Btu/h $E = 0.10\ lb/10^6$ Btu

(continued)

NEW YORK (continued)

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other			
State	1	20	3	2	40	0										x[1]	1. Opacity > 250 x 10^6 Btu/h fuel combustion sources (except gas-fired) and Portland cement kilns and Chinker coolers only.

NORTH CAROLINA

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations							Footnotes
	Aggregrate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10⁶ Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other	Reference figure	Measurement method	
State	X			X						X		X[1,2]					1-24[1] 1-25[2]		1. $Q \leq 10 \times 10^6$ Btu/h $E = 0.6$ lb/10^6 Btu $10 < Q < 10{,}000$ $E = 1.090Q^{-0.2594}$ $Q \geq 10{,}000$ $E = 0.10$ lb/10^6 Btu 2. Wood-burning units $Q \leq 10 \times 10^6$ Btu/h $E = 0.70$ lbs/10^6 Btu $Q > 10 \times 10^6$ Btu/h $E = 1.1698Q^{-0.2230}$

(continued)

NORTH CAROLINA (continued)

PART B. VISIBLE EMISSION REGULATIONS

Political Jurisdiction	Existing sources[1]							New sources							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other			
State	2	40	5[2]					1	20	5[2]						X	1. Installations existing as of July 1, 1971. 2. 20 min. in any 24-h.

NORTH DAKOTA

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations							Footnotes
	Aggregate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10⁶ Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other	Reference figure	Measurement method	
State	X			X						X		X[1,2]					1-26[2]		1. Existing $E = 0.8\ lb/10^6$ Btu 2. New (constructed after 12-15-73) $Q \leq 10 \times 10^6$ Btu/h $E = 0.6\ lb/10^6$ Btu $Q > 10 \times 10^6$ Btu/h $E = 0.811Q^{-0.131}$

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources[1]							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than — minutes in any 1 hour	Ringelmann	Opacity	No more than — minutes in any 1 hour	Other	Ringelmann	Opacity	No more than — minutes in any 1 hour	Ringelmann	Opacity	No more than — minutes in any 1 hour	Other			
State	2	40		3	60	4		1	20		3	60	4				1. Constructed after 12-15-73.

OHIO

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations					Reference figure	Measurement method	Footnotes
	Aggregate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	$lb/10^6$ Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other			
State			X	X						X		X[1]					1-37 1-38	PTC-27	1. Priority I regions - curve 1-37. Priority II and III regions - 1-38.

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other			
State	1	20		3	60	3											

OKLAHOMA

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations					Reference figure	Measurement method	Footnotes
	Aggregate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10⁶ Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other			
State		X			X				X			X[1]					1-27		
Tulsa	X											X[2]					1-28		

1.

Q, 10^6 Btu/h	E, lb PM/10^6 Btu
≤10	0.6
100	0.35
1,000	0.20
≥10,000	0.10

2.

Q, 10^6 Btu/h	E, lb PM/10^6 h
≤10	0.60
100	0.35
1,000	0.20
≥10,000	0.12

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than — minutes in any 1 hour	Ringelmann	Opacity	No more than — minutes in any 1 hour	Other	Ringelmann	Opacity	No more than — minutes in any 1 hour	Ringelmann	Opacity	No more than — minutes in any 1 hour	Other			
State	1	20		3		5[1]										X	1. 20 min in any 24-h.
Tulsa	2					6		1					6				

OREGON

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations							Footnotes
	Aggregrate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10⁶ Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other	Reference figure	Measurement method	
State							NS[1]			X					X[2]				1. NS denotes not specified. 2. Existing - 0.2 gr/scf. New - 0.1 gr/scf (constructed after 6-1-70)

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources[1]							New sources[2]							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than — minutes in any 1 hour	Ringelmann	Opacity	No more than — minutes in any 1 hour	Other	Ringelmann	Opacity	No more than — minutes in any 1 hour	Ringelmann	Opacity	No more than — minutes in any 1 hour	Other			
State	2	40	3					1	20	3							1. Existing sources outside special control area and all existing wood waste boilers. 2. New sources in all areas and existing sources inside the special control area (constructed after 6-1-70).

PENNSYLVANIA

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations					Reference figure	Measurement method
	Aggregrate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10⁶ Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other		
State	X				X				X			X[1]					1-29	
Allegheny Co.	X				X				X			X[2]					1-30	
Philadelphia Co.	X				X				X			X[3,4,5]						

Footnotes

1\.

Q, 10^6 Btu/h	E, lb/10^6 Btu
$2.5 < Q \leq 50$	0.4
$50 < Q \leq 600$	$E = 3.6Q^{-0.56}$
$Q \geq 600$	0.1

2\.

Q, 10^6 Btu/h	E, lb/10^6 Btu
$0.2 < Q \leq 50$	0.40
$50 < Q \leq 850$	$E = 3.5Q^{-0.56}$
$Q \geq 850$	0.08

3. Units built prior to 4-10-79 must meet 0.2 lb/10^6 Btu.

4. Units built after 4-10-79 must meet 0.1 lb/10^6 Btu.

5. Coal conversions must meet 0.12 lb/10^6 Btu after 7-1-80 and 0.06 lb/10^6 Btu after 7-1-84.

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources[2]							Measurement method	Continuous monitoring requirement
	Requirement			Exception				Requirement			Exception					
	Ringelmann	Opacity	No more than — minutes in any 1 hour	Ringelmann	Opacity	No more than — minutes in any 1 hour	Other	Ringelmann	Opacity	No more than — minutes in any 1 hour	Ringelmann	Opacity	No more than — minutes in any 1 hour	Other		
State		20	3		60	0			20	3		60	0		X[1]	
Philadelphia & Allegheny Counties	1	20	3	3	60	0		1	20	3	3	60	0			

Footnotes

1. Devices approved by the Department and maintained to provide opacity measurements, or by trained observers.

2. Allegheny County new are those constructed after 8-17-71.

RHODE ISLAND

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations							Footnotes
	Aggregrate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10^6 Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other	Reference figure	Measurement method	
State		X		X						X		X[1]							1. Q, 10^6 Btu/h E, lb/10^6 Btu $1 < Q < 250$ 0.2 $Q \geq 250$ 0.1

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than — minutes in any 1 hour	Ringelmann	Opacity	No more than — minutes in any 1 hour	Other	Ringelmann	Opacity	No more than — minutes in any 1 hour	Ringelmann	Opacity	No more than — minutes in any 1 hour	Other			
State	1	20	3													X[1]	1. General opacity requirements for steam generators burning No. 6 oil or solid fuel and steam generators burning all liquid fuel > 5 x 10^6 Btu/h.

SOUTH CAROLINA

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations					Reference figure	Measurement method	Footnotes
	Aggregrate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10^6 Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other			
State		X		X						X		X[1]					1-31		1. $Q < 1300 \times 10^6$ Btu/h $E = 0.6$ lb/10^6 Btu $Q \geq 1300 \times 10^6$ Btu/h $E = 57.84Q^{-0.637}$ Except existing sources prior to February 11, 1971. $Q < 10 \times 10^6$ Btu/h $E = 0.8$ lb/10^6 Btu

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources[1]							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other			
State	2			3		5[2]		1			3		5[2]			X[3]	1. Constructed after 2-11-71. 2. 20 min in 24-h period. 3. Required for steam generators > 250×10^6 Btu/h except where only gaseous fuel is burned, oil or a mixture of gas and oil is burned and PM and visible emission requirements are met, or the annual average opacity factor is 30% or less.

SOUTH DAKOTA

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations					Reference figure	Measurement method	Footnotes
	Aggregrate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10⁶ Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other			
State		X		X				X				X[1]							1. Solid fuel or fuel oil E = 0.30 lb/10^6 Btu

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other			
State	1	20		3	60	3											

TENNESSEE

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations							Footnotes
	Aggregrate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	$lb/10^6$ Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other	Reference figure	Measurement method	
State	X			X						X		X[1]					I-32 I-33		1. Diffusion equation if $Q < 400 \times 10^6$ Btu/h $E = \frac{20650\ ah}{Q^{0.75}}$ $a = 0.67$ if stack height $(h) \leq 200$ ft 0.80 if $h > 200$ ft **Note**: when more than one stack exists, E is divided by $(N)^{0.25}$ where N = number of stacks or use Fig. I-32 and I-33. Existing Q, 10^6 Btu/h — E, $lb/10^6$ Btu $Q \leq 10$ — 0.6 $10 < Q < 10{,}000$ — $1.0903Q^{-0.2594}$ $Q \geq 10{,}000$ — 0.10

(continued)

TENNESSEE (continued)

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations					Reference figure	Measurement method	Footnotes
	Aggregrate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10^6 Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other			
															x^2				New (constructed after 4-3-72) $Q \leq 10$ 0.60 $10 < Q < 250$ $2.1617Q^{-0.5566}$ $Q \geq 250$ 0.10 2. Wood-fired units existing (corrected to 12% CO_2) $Q \leq 50 \times 10^6$ Btu/h E = 0.33 gr/sdcf $Q \geq 100 \times 10^6$ Btu/h E = 0.10 lb/10^6 Btu Interpolate 50-100 Btu/h New (constructed after 4-3-72) $Q \leq 25 \times 10^6$ Btu/h E = 0.33 gr/sdcf

(continued)

TENNESSEE (continued)

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations					Reference figure	Measurement method	Footnotes
	Aggregrate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10^6 Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other			
Hamilton Co.		X		X						X		X^3					1-32 1-33		$Q \leq 100 \times 10^6$ Btu/h E = 0.20 gr/sdcf Interpolate 25-100 Btu/h 3. Existing - Schedule I New - Schedule 2 or schedule 3 if built after January 1, 1975 Q, 10^6 Btu/h — E, lb/10^6 Btu I II III 0-10 — 0.60 0.60 0.60 100 — 0.40 0.33 0.17 1,000 — 0.27 0.18 0.10

(continued)

TENNESSEE (continued)

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources[1]							Measurement method	Continuous monitoring requirement
	Requirement			Exception				Requirement			Exception					
	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other		
State	1	20	5[2]					1	20	5[2]						X
All areas except Davidson, Hamilton, Knox and Shelby Co.[3]	2	40						2	40							

Footnotes

1. Constructed after 4-3-72.
2. 20 min in any 24-h.
3. Wood-fired units > 100 x 10^6 Btu/h. If other emission sources exhaust through the same stack:

$$V = \frac{40.0\ V_W + 20.0\ V_R}{V_W + V_R}$$

where: V = opacity standard, %
V_W = exhaust flow rate, dscf, from wood-fired unit
V_R = exhaust flow rate, dscf, other emission sources.

TEXAS

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations					Reference figure	Measurement method	Footnotes
	Aggregate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10⁶ Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other			
State	X				X				X			x^1							1. Solid fossil fuel fired steam generators 0.3 lb/10^6 Btu
													x^2				6-1		2. $E = 0.048$ (stack flow rate adfm)$^{-0.62}$ Note: E is adjusted if the effective stack height of the source is less than the standard effective stack height as determined by $H_e = 1.05$ (flow rate)$^{0.35}$.
																x^3	6-2		3. Maximum ground level concentrations on a property 100 μg/m^3 (5-h avg) 200 μg/m^3 (3-h avg) 400 μg/m^3 (1-h avg)

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources[1]							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other			
State		30	5						20	5						x^3	1. Constructed after 1-31-72.
		15	5^2						15	5^2							2. Sources with flow rate ≥ 100,000 acfm unless opacity monitor is installed in flue.
																	3. General opacity requirement for any stationary flue with more than 100,000 acfm and greater than 15% opacity averaged over a 5 minute period. General SO_2 requirements for primary nonferrous smelters and any sulfuric acid plant using SO_2 control on such smelters.

UTAH

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations					Reference figure	Measurement method	Footnotes
	Aggregate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10^6 Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other			
State		X		X					X			X[1]							1. 10 lbs/10^6 Btu (0.18 gr/mm calories).

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources[1]							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other			
State		40				3			20				3				1. Constructed after 4-25-71.
Wasatch Front area		20				3											

VERMONT

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations					Reference figure	Measurement method	Footnotes
	Aggregrate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10^6 Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other			
State		X				X				X		X[1]					1-34		1. Existing $Q \leq 10 \times 10^6$ Btu/h $E = 0.5$ lb/10^6 Btu (0.90 g/10^6 cal) $10 < Q < 300$ $E = 1.4865Q^{-0.4732}$ $Q \geq 300$ $E = 1.0$ lb/10^6 Btu (0.18 g/10^6 cal)

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources[1]							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other			
State	3	60	0					3	60	0							1. Constructed after 7-1-71.
	2	40	6					1	20	6							

VIRGINIA

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations							Footnotes
	Aggregrate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10⁶ Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other	Reference figure	Measurement method	
State			X	X						X		x^1							1. $Q < 10 \times 10^6$ Btu/h $E = 0.6$ lb/10^6 Btu $10 \leq Q < 10{,}000 \times 10^6$ Btu/h $E = 1.096H^{-0.2594}$ $Q \geq 10{,}000 \times 10^6$ Btu/h $E = 0.10$ lb/10^6 Btu 2. $Q < 100 \times 10^6$ Btu/h $E = 0.3$ lb/10^6 Btu $100 < Q < 10{,}000 \times 10^6$ Btu/h $E = 0.900H^{-0.2386}$ $Q > 10{,}000 \times 10^6$ Btu/h $E = 0.10$ lb/Btu
AQCR 7												x^2							

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other			
State		20														X	

WASHINGTON

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations							Footnotes
	Aggregrate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10⁶ Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other	Reference figure	Measurement method	
State							NS[6]	X							X[1]				1. Existing - 0.20 gr/dscf New - 0.10 gr/dscf (constructed after 10-5-73)
NW Air Pollution Control Auth.															X[2]				2. Existing - 0.20 gr/scf New - 0.05 gr/scf
Puget Sound															X[3,4]				3. Existing - 0.10 g/scf New - 0.05 g/scf
SW Air Pollution Control Auth.															X[5]				4. Wood residue Existing - 0.20 gr/scf New - 0.10 gr/scf
Olympic Air Pollution Control Auth.															X[1]				5. 0.10 gr/scf Hog-fuel - 0.2 gr/scf Natural gas - 0.3 gr/scf
																			6. NS denotes not specified.

(continued)

WASHINGTON (continued)

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources[6]							Measurement method	Continuous monitoring requirement
	Requirement			Exception				Requirement			Exception					
	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other		
State		40	3[1,2]						20	3[1,3]						X
NW Air Pollution Auth.	2	40	3[1,2]													
Puget Sound	2	40	3[4]					1	20		2	40	15			
SW Air Pollution Control Auth.	2		3	2-3		6[5]		1		3						
Olympic Air Pollution Control	2	40	3	2-3		6[5]		1	20	3						
Yakima Co. Clean Air Auth.	1	20	3													
Spokane Co. Air Pollution Control Auth.	1	20	3					1	20	3						

Footnotes

1. Not exceed 15 min in any consecutive 8-h.
2. Does not apply if source meeting < 0.20 gr/dscf.
3. Does not apply if source meeting < 0.10 gr/dscf.
4. Does not apply to equipment utilizing wood residue when source is meeting < 0.05 gr/scf.
5. Hog fuel boiler.
6. Constructed after 10-5-73.

WEST VIRGINIA

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations					Reference figure	Measurement method	Footnotes
	Aggregrate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10⁶ Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other			
State		X		X				X				$X^{1,2}$					5-2		1. If plant is expanded by addition of new unit, allowable emission rate for new unit shall be determined as follows: $R_e = \left[1 - \left(\frac{H_{et} - R_{et}}{H_{et}}\right)\right] H_e$ where, R_e = total allowable emission rate in pounds per hour for the new fuel burning unit(s); H_{et} = total design heat input in 10^6 Btu's/h of the existing and new similar units; R_{et} = total allowable emission rate in lbs/h corresponding to H_{et}; and H_e = total design heat input in 10^6 Btu's/h for the new fuel burning unit(s). 2. Type "a" units Product of 0.05 and total design heat inputs, no more than 1200 lbs/h. Type "b" units Product of 0.09 and total design heat inputs, no more than 600 lbs/h. Type "c" units 10^6 Btu/h — lb/h 10 — 3.4 100 — 16.6 3,333 — 300.0 No more than 300 lb/h where: (1) Type "a" is any unit which has primary purpose of generating steam to produce electric power for sale. (2) Type "b" is any unit not classified as "a" or "c". (3) Type "c" is any hand-fired or stoker-fired unit.

(continued)

WEST VIRGINIA (continued)

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources							Measurement method	Continuous moni-toring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than minutes in any 1 hour	Ringelmann	Opacity	No more than minutes in any 1 hour	Other	Ringelmann	Opacity	No more than minutes in any 1 hour	Ringelmann	Opacity	No more than minutes in any 1 hour	Other			
State	.5			1		8[1]										x[4]	1. Exemption applies to soot blowing and firebox cleaning and is applicable during any 8 h period. 2. Exemption applies to start-up of units except hand-fired or stoker-fired. 3. Exemption applies to start-up of hand-fired or stoker-fired units. Ringelman #3 for first 45 minutes, Ringelman #2 for remaining 75 minutes. 4. Director may require - general requirement.
				2		120[2]											
				2		120[3]											
				3		120[3]											

WISCONSIN

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations					Reference figure	Measurement method	Footnotes
	Aggregrate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10⁶ Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other			
State		X				X				X		X[1]					3-2 3-3 3-4 3-5		1. Category I - New or modified sources (except in Southeast Wisconsin Intrastate AQCR) $Q \leq 250 \times 10^6$ Btu/h $E = 0.15$ lb/10^6 Btu $Q > 250 \times 10^6$ Btu/h $E = 0.10$ lb/10^6 Btu Existing Lake Michigan Intrastate AQCR Fig. 3-5 (ASME No. APS-1) with maximum E, irrespective of H, 0.6 lb/10^6 Btu. All sources in Southeast Wisconsin Intrastate AQCR. ($Q < 250 \times 10^6$ Btu/h - Not permitted to burn coal). All sources - 0.15 lb/10^6 Btu. Existing sources (except Michigan and S.E. Wisconsin Intrastate AQCR's) Fig. 3-6 (ASME NO APS-1) with max $E = 0.3$ lb/10^6 Btu.

(continued)

WISCONSIN (continued)

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources[1]							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other			
Category I								1	20		4	80	5[2]				1. Constructed after 4-1-72.
Category II - control plan submitted by July 1, 1971, compliance by July 1, 1973	2	40		4	80	5[2]											2. Cleaning and starting fire but not more than 3 times/day. If stack test is run concurrently with Ringelmann test, opacity should be set 10% above average read by stack test.
Category III or IV - Lake Interstate AQCR, Southeast Wisconsin Intrastate	1	20		4	80	5[2]											

WYOMING

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations					Reference figure	Measurement method	Footnotes
	Aggregrate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10⁶ Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other			
State		X		X						X		X[1]					1-41		1. Existing

$Q, 10^6$ Btu/h	E, lb/10^6 Btu
$Q \leq 10$	0.6
$10 < Q < 10,000$	$0.8963I^{-0.1743}$
$Q \geq 10,000$	0.18

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources[1]							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other			
State[2]		40	6						20			40	6				1. Constructed after 4-9-73. 2. Source specific opacity limits will be established for large fuel burning units which can not meet 20% opacity limit.

AMERICAN SAMOA

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations					Reference figure	Measurement method	Footnotes
	Aggregrate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10^6 Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other			
Territory			X			X		X				X[1]							1. 0.10 lb/10^6 Btu.

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than — minutes in any 1 hour	Ringelmann	Opacity	No more than — minutes in any 1 hour	Other	Ringelmann	Opacity	No more than — minutes in any 1 hour	Ringelmann	Opacity	No more than — minutes in any 1 hour	Other			
Territory	1	20		3	60	3											

GUAM

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations					Reference figure	Measurement method	Footnotes
	Aggregrate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10^6 Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other			
Territory							NS[1]				NS[1]								1. NS denotes not specified.

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources							Measurement method	Continuous moni-toring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other			
Territory	1	20		3	60	3											

PUERTO RICO

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations							Footnotes
	Aggregrate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10^6 Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other	Reference figure	Measurement method	
Territory	X					X				X		X[1]							1. 0.30 lb/10^6 Btu.

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other			
Territory	1	20		3	60	4[1]											1. Any 30 minutes.

VIRGIN ISLANDS

PART A. ALLOWABLE MASS EMISSION RATE FOR INDIRECT HEAT EXCHANGERS

Political jurisdiction	Total heat input based on:							Allowable emissions based on:				Units of the regulations							Footnotes
	Aggregrate of all fuels burned	Maximum design	Maximum of design or burned	All units	Individual units	Individual stack	Other	Entire plant	Individual unit	Individual stack	Other	lb/10^6 Btu	lb/h	lb/1000 lb stack gas	Grains/scf	Other	Reference figure	Measurement method	
Territory	X				X				X			X[1]					1-42		1. 10^6/h — lb/10^6 Btu ≤ 10 — 0.60 100 — 0.352 1,000 — 0.207 ≥ 10,000 — 0.09

PART B. VISIBLE EMISSION REGULATIONS

Political jurisdiction	Existing sources							New sources							Measurement method	Continuous monitoring requirement	Footnotes
	Requirement			Exception				Requirement			Exception						
	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Ringelmann	Opacity	No more than __ minutes in any 1 hour	Other			
Territory	2	40						1	20		2	40	6				

REFERENCES

1. Regulations and Non-Regulatory Revisions to State Implementation Plan: Alabama. EPA 450/2-80-007. July 1980.
2. Regulations and Non-Regulatory Revisions to State Implementation Plan: Alaska. EPA 450/2-80-008. July 1980.
3. Regulations and Non-Regulatory Revisions to State Implementation Plan: Arizona. EPA 450/2-80-009. July 1980.
4. Regulations and Non-Regulatory Revisions to State Implementation Plan: Arkansas. EPA 450/2-80-010. July 1980.
5. Regulations and Non-Regulatory Revisions to State Implementation Plan: California. EPA 450/2-80-011. July 1980.
6. Regulations and Non-Regulatory Revisions to State Implementation Plan: Colorado. EPA 450/2-80-012. July 1980.
7. Regulations and Non-Regulatory Revisions to State Implementation Plan: Connecticut. EPA 450/2-80-013. July 1980.
8. Regulations and Non-Regulatory Revisions to State Implementation Plan: Delaware. EPA 450/2-80-014. July 1980.
9. Regulations and Non-Regulatory Revisions to State Implementation Plan: District of Columbia. EPA 450/2-80-015. July 1980.
10. Regulations and Non-Regulatory Revisions to State Implementation Plan: Florida. EPA 450/2-80-016. July 1980.
11. Regulations and Non-Regulatory Revisions to State Implementation Plan: Georgia. EPA 450/2-80-017. July 1980.
12. Regulations and Non-Regulatory Revisions to State Implementation Plan: Hawaii. EPA 450/2-80-018. July 1980.
13. Regulations and Non-Regulatory Revisions to State Implementation Plan: Idaho. EPA 450/2-80-019. July 1980.
14. Regulations and Non-Regulatory Revisions to State Implementation Plan: Illinois. EPA 450/2-80-020. July 1980.
15. Regulations and Non-Regulatory Revisions to State Implementation Plan: Indiana. EPA 450/2-80-021. July 1980.

16. Regulations and Non-Regulatory Revisions to State Implementation Plan: Iowa. EPA 450/2-80-022. July 1980.

17. Regulations and Non-Regulatory Revisions to State Implementation Plan: Kansas. EPA 450/2-80-023. July 1980.

18. Regulations and Non-Regulatory Revisions to State Implementation Plan: Kentucky. EPA 450/2-80-024. July 1980.

19. Regulations and Non-Regulatory Revisions to State Implementation Plan: Louisiana. EPA 450/2-80-025. July 1980.

20. Regulations and Non-Regulatory Revisions to State Implementation Plan: Maine. EPA 450/2-80-026. July 1980.

21. Regulations and Non-Regulatory Revisions to State Implementation Plan: Maryland. EPA 450/2-80-027. July 1980.

22. Regulations and Non-Regulatory Revisions to State Implementation Plan: Massachusetts. EPA 450/2-80-028. July 1980.

23. Regulations and Non-Regulatory Revisions to State Implementation Plan: Michigan. EPA 450/2-80-029. July 1980.

24. Regulations and Non-Regulatory Revisions to State Implementation Plan: Minnesota. EPA 450/2-80-030. July 1980.

25. Regulations and Non-Regulatory Revisions to State Implementation Plan: Mississippi. EPA 450/2-80-031. July 1980.

26. Regulations and Non-Regulatory Revisions to State Implementation Plan: Missouri. EPA 450/2-80-032. July 1980.

27. Regulations and Non-Regulatory Revisions to State Implementation Plan: Montana. EPA 450/2-80-033. July 1980.

28. Regulations and Non-Regulatory Revisions to State Implementation Plan: Nebraska. EPA 450/2-80-034. July 1980.

29. Regulations and Non-Regulatory Revisions to State Implementation Plan: Nevada. EPA 450/2-80-035. July 1980.

30. Regulations and Non-Regulatory Revisions to State Implementation Plan: New Hampshire. EPA 450/2-80-036. July 1980.

31. Regulations and Non-Regulatory Revisions to State Implementation Plan: New Jersey. EPA 450/2-80-037. July 1980.

32. Regulations and Non-Regulatory Revisions to State Implementation Plan: New Mexico. EPA 450/2-80-038. July 1980.

33. Regulations and Non-Regulatory Revisions to State Implementation Plan: New York. EPA 450/2-80-039. July 1980.

34. Regulations and Non-Regulatory Revisions to State Implementation Plan: North Carolina. EPA 450/2-80-040. July 1980.

35. Regulations and Non-Regulatory Revisions to State Implementation Plan: North Dakota. EPA 450/2-80-041. July 1980.

36. Regulations and Non-Regulatory Revisions to State Implementation Plan: Ohio. EPA 450/2-80-042. July 1980.

37. Regulations and Non-Regulatory Revisions to State Implementation Plan: Oklahoma. EPA 450/2-80-043. July 1980.

38. Regulations and Non-Regulatory Revisions to State Implementation Plan: Oregon. EPA 450/2-80-044. July 1980.

39. Regulations and Non-Regulatory Revisions to State Implementation Plan: Pennsylvania. EPA 450/2-80-045. July 1980.

40. Regulations and Non-Regulatory Revisions to State Implementation Plan: Rhode Island. EPA 450/2-80-046. July 1980.

41. Regulations and Non-Regulatory Revisions to State Implementation Plan: South Carolina. EPA 450/2-80-047. July 1980.

42. Regulations and Non-Regulatory Revisions to State Implementation Plan: South Dakota. EPA 450/2-80-048. July 1980.

43. Regulations and Non-Regulatory Revisions to State Implementation Plan: Tennessee. EPA 450/2-80-049. July 1980.

44. Regulations and Non-Regulatory Revisions to State Implementation Plan: Texas. EPA 450/2-80-050. July 1980.

45. Regulations and Non-Regulatory Revisions to State Implementation Plan: Utah. EPA 450/2-80-051. July 1980.

46. Regulations and Non-Regulatory Revisions to State Implementation Plan: Vermont. EPA 450/2-80-052. July 1980.

47. Regulations and Non-Regulatory Revisions to State Implementation Plan: Virginia. EPA 450/2-80-053. July 1980.

48. Regulations and Non-Regulatory Revisions to State Implementation Plan: Washington. EPA 450/2-80-054. July 1980.

49. Regulations and Non-Regulatory Revisions to State Implementation Plan: West Virginia. EPA 450/2-80-055. July 1980.

50. Regulations and Non-Regulatory Revisions to State Implementation Plan: Wisconsin. EPA 450/2-80-056. July 1980.

51. Regulations and Non-Regulatory Revisions to State Implementation Plan: Wyoming. EPA 450/2-80-057. July 1980.

52. Regulations and Non-Regulatory Revisions to State Implementation Plan: American Samoa. EPA 450/2-80-058. July 1980.

53. Regulations and Non-Regulatory Revisions to State Implementation Plan: Gaum. EPA 450/2-80-059. July 1980.

54. Regulations and Non-Regulatory Revisions to State Implementation Plan: Puerto Rico. EPA 450/2-80-060. July 1980.

55. Regulations and Non-Regulatory Revisions to State Implementation Plan: Virgin Islands. EPA 450/2-80-061. July 1980.

56. State Implementation Plans Emission. Regulations for Particulate Matter: Fuel Combustion. EPA 450/2-76-010. August 1976.

57. Control of Particulate Matter from Oil Burners and Boilers. EPA 450/3-76-005. April 1976.

58. Compilation of Air Pollutant Emission Factors. Second edition. AP-42. February 1980.

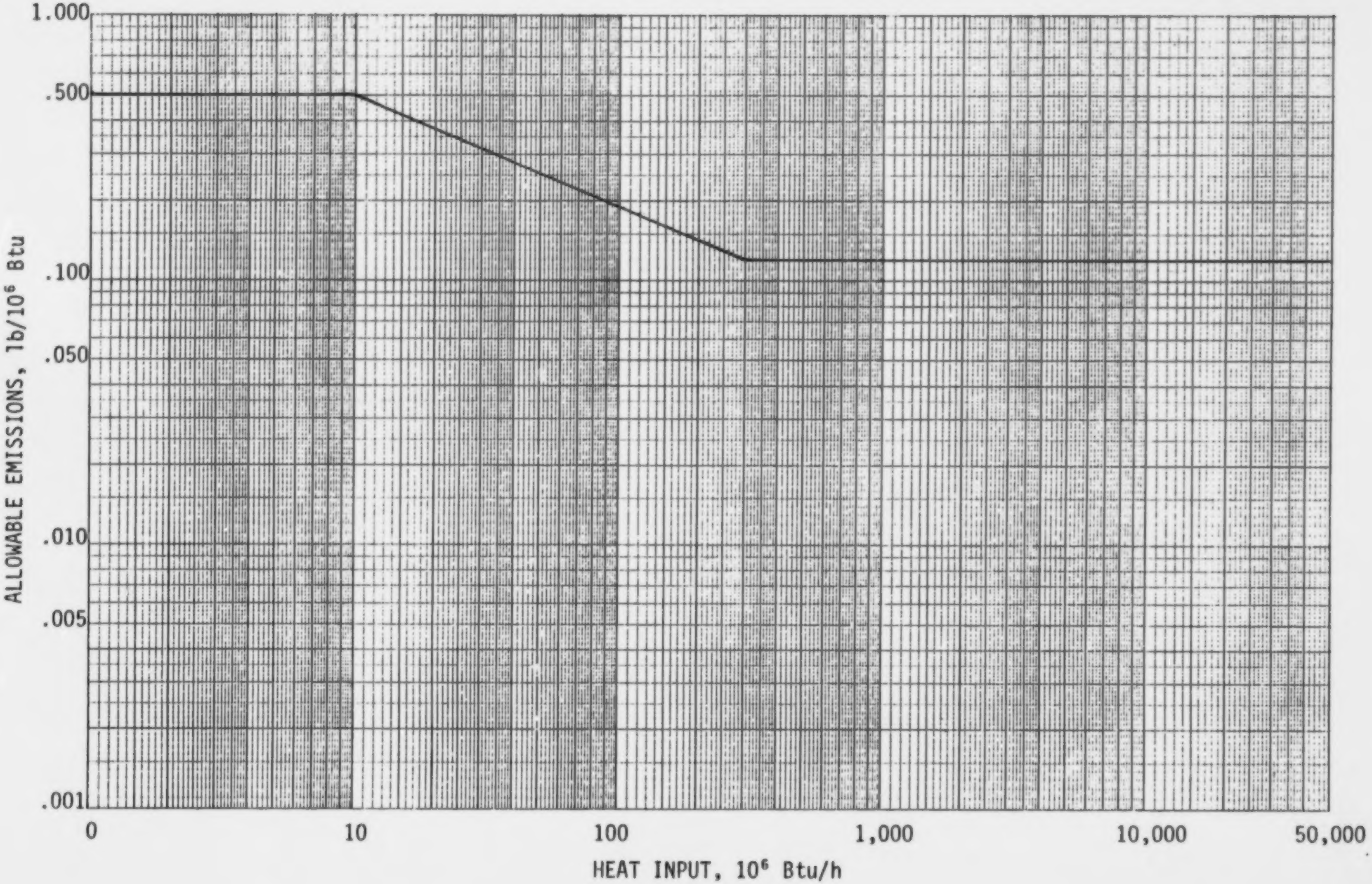
59. Smith, W. S. and C. W. Gruber. Atmospheric Emissions from Coal Combustion. An Inventory Guide. U.S. Department of Health Education and Welfare. AP-24. April 1966.

60. Roek, D. R., and R. Dennis. Technology Assessment Report for Industrial Boiler Applications: Particulate Collection. EPA 600/7-79-178h. December 1979.

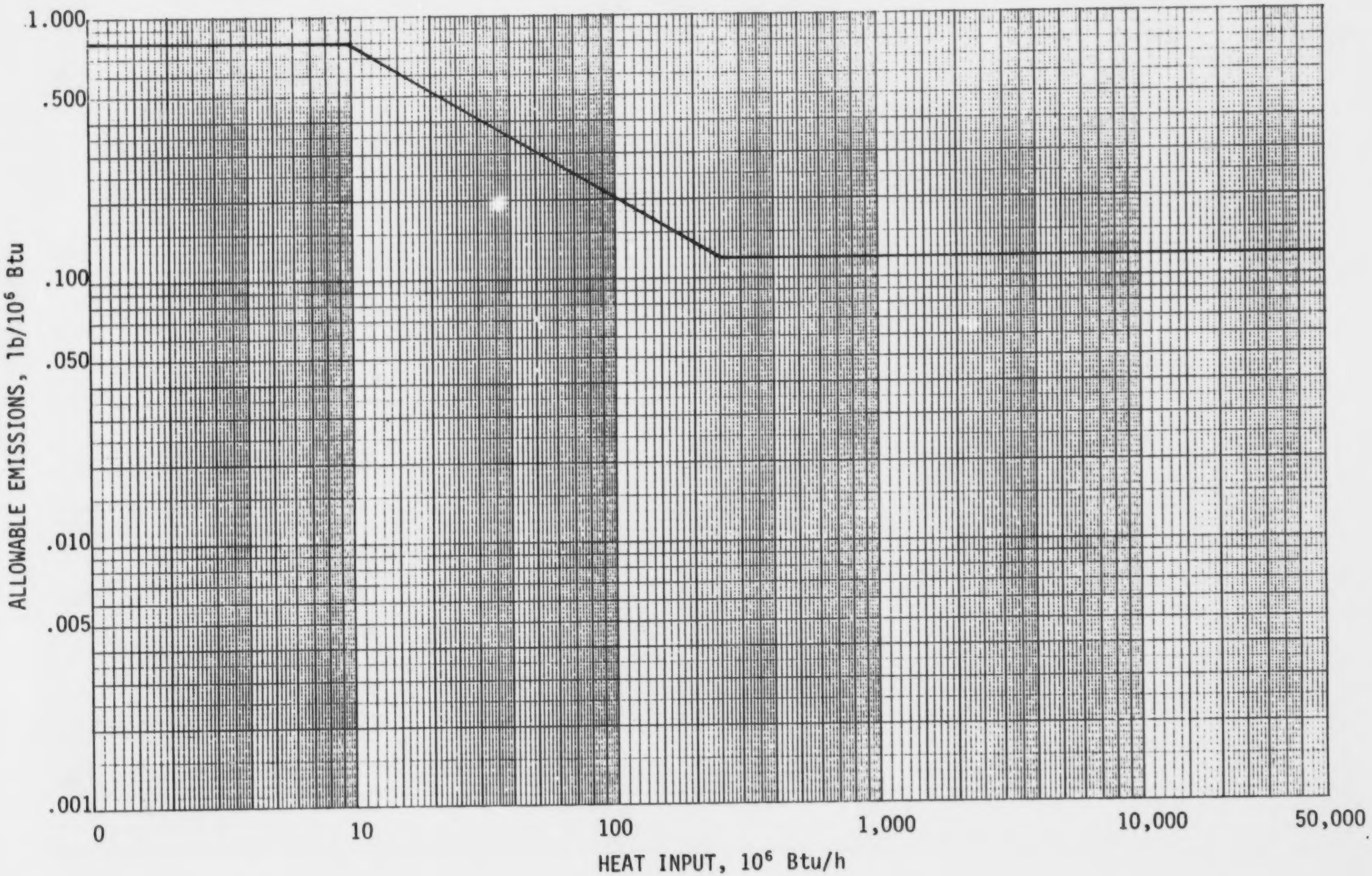
61. Compilation and Analysis of State Regulations for SO_2, NO_x, Opacity, Continuous Monitoring, and Applicable Test Methods. Prepared for U.S. Environmental Protection Agency by Engineering Science under EPA Contract No. 68-01-4146, Task No. 40. June 1978.

APPENDIX A

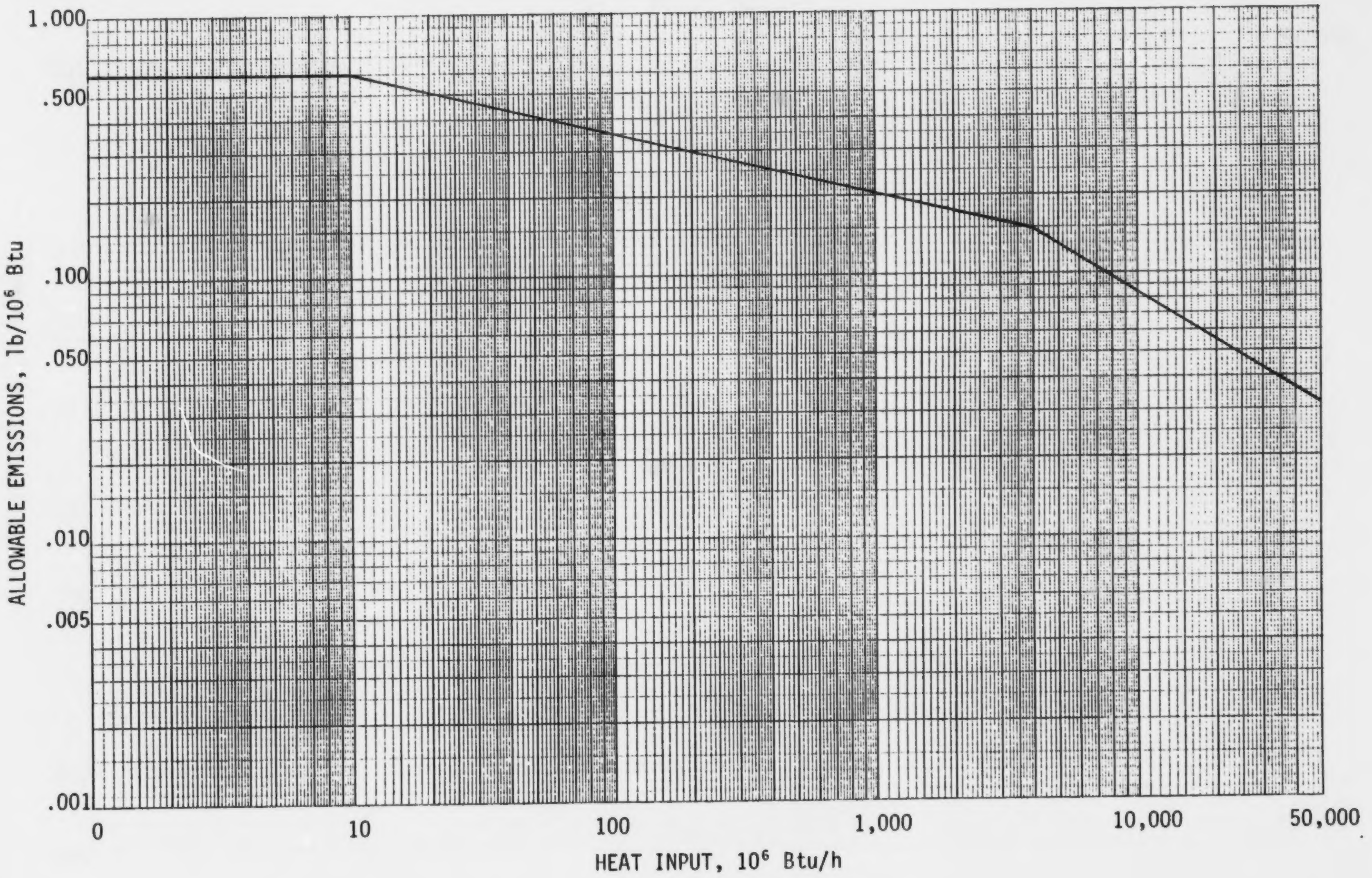
REFERENCE FIGURES FOR ALLOWABLE EMISSION RATES



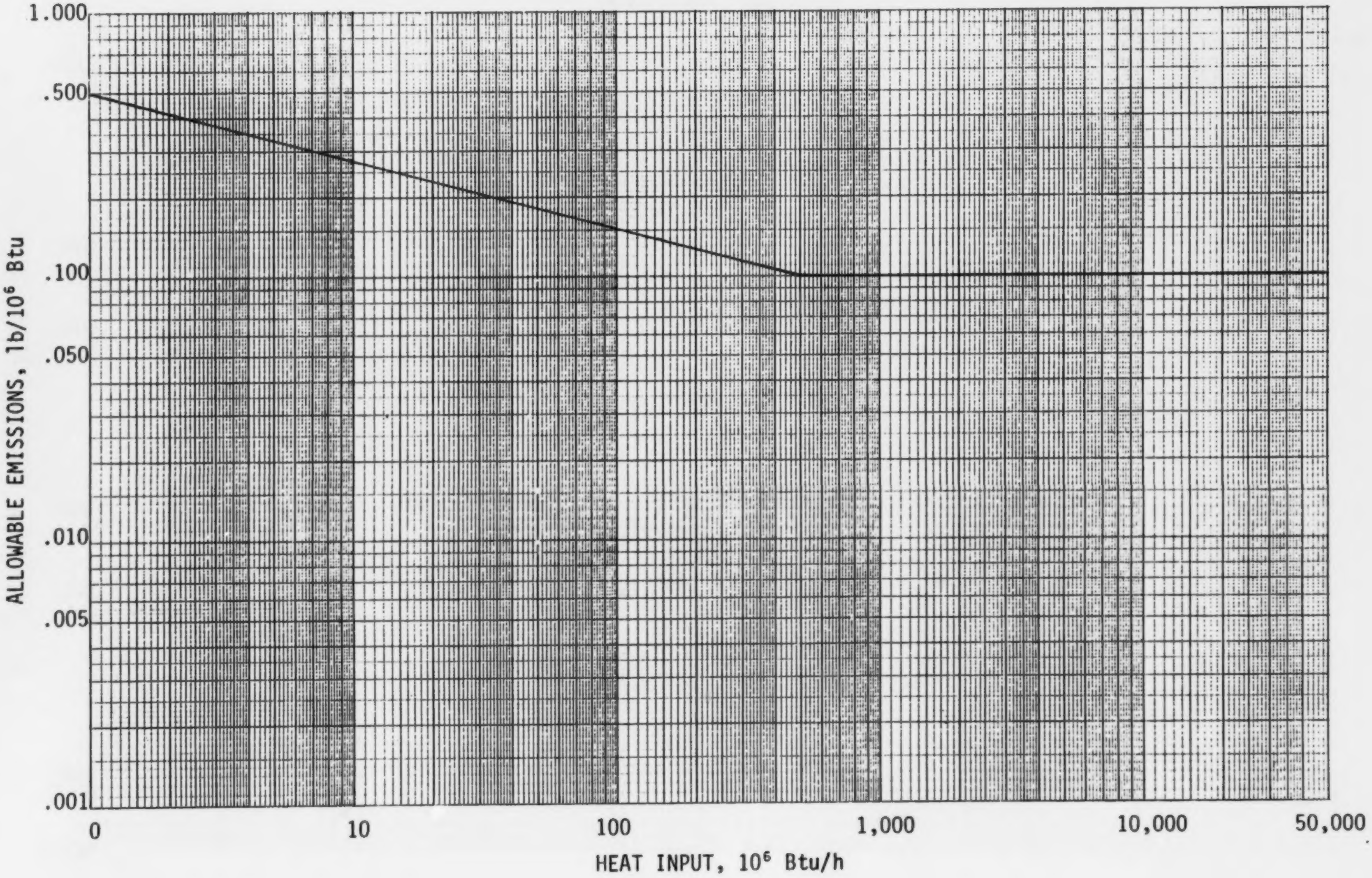
Reference Figure 1-1.



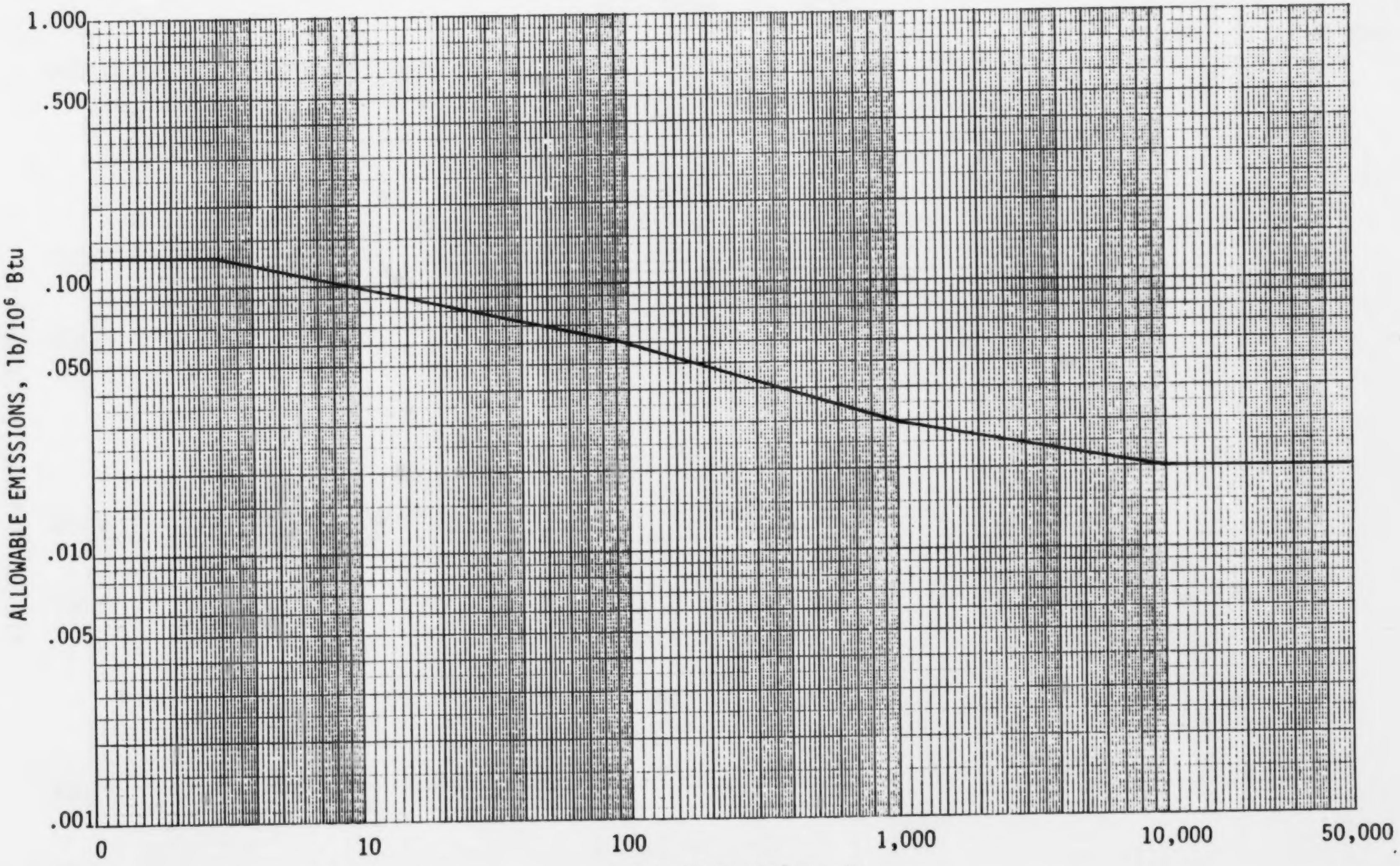
Reference Figure 1-2.



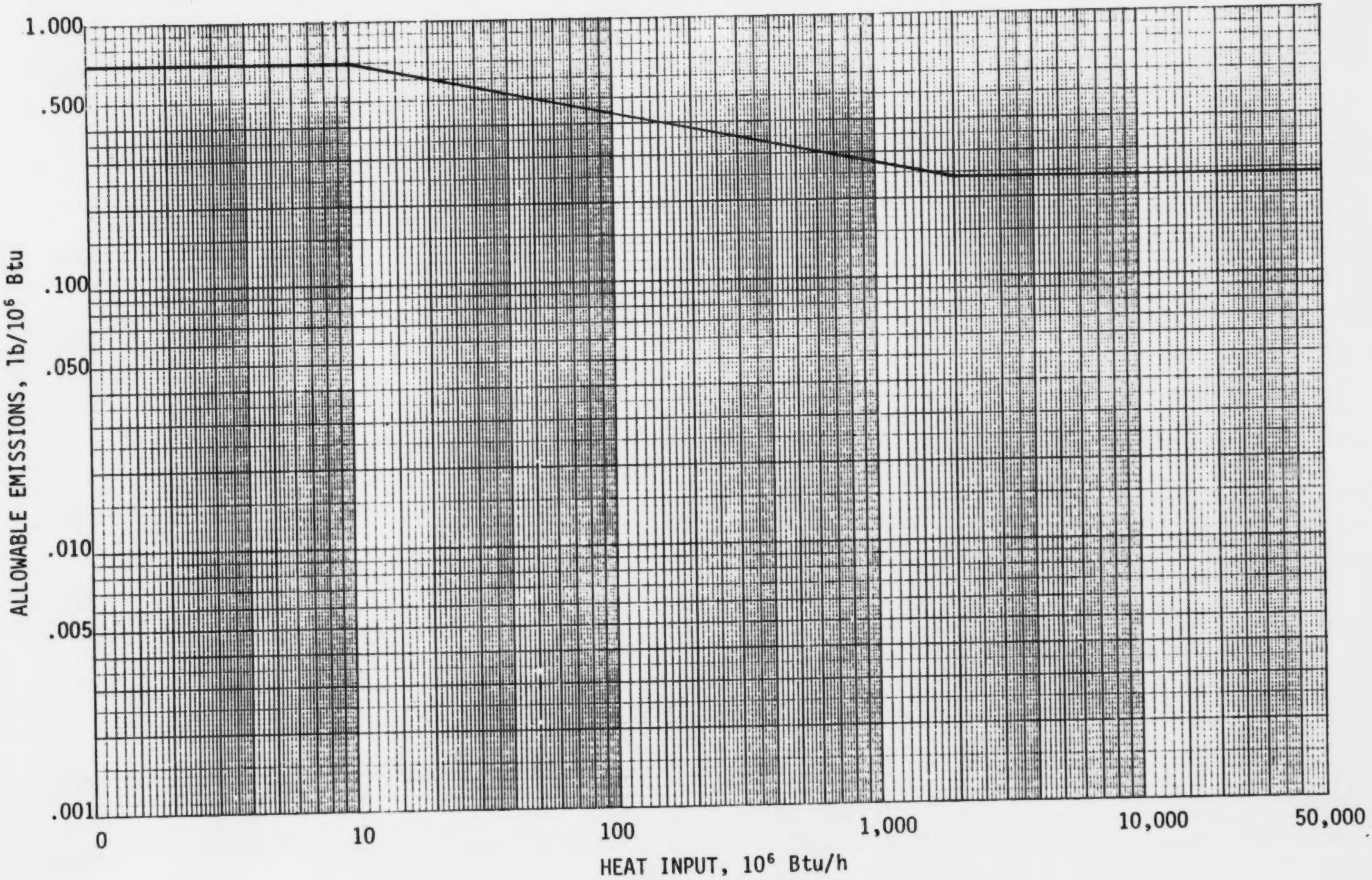
Reference Figure 1-3.



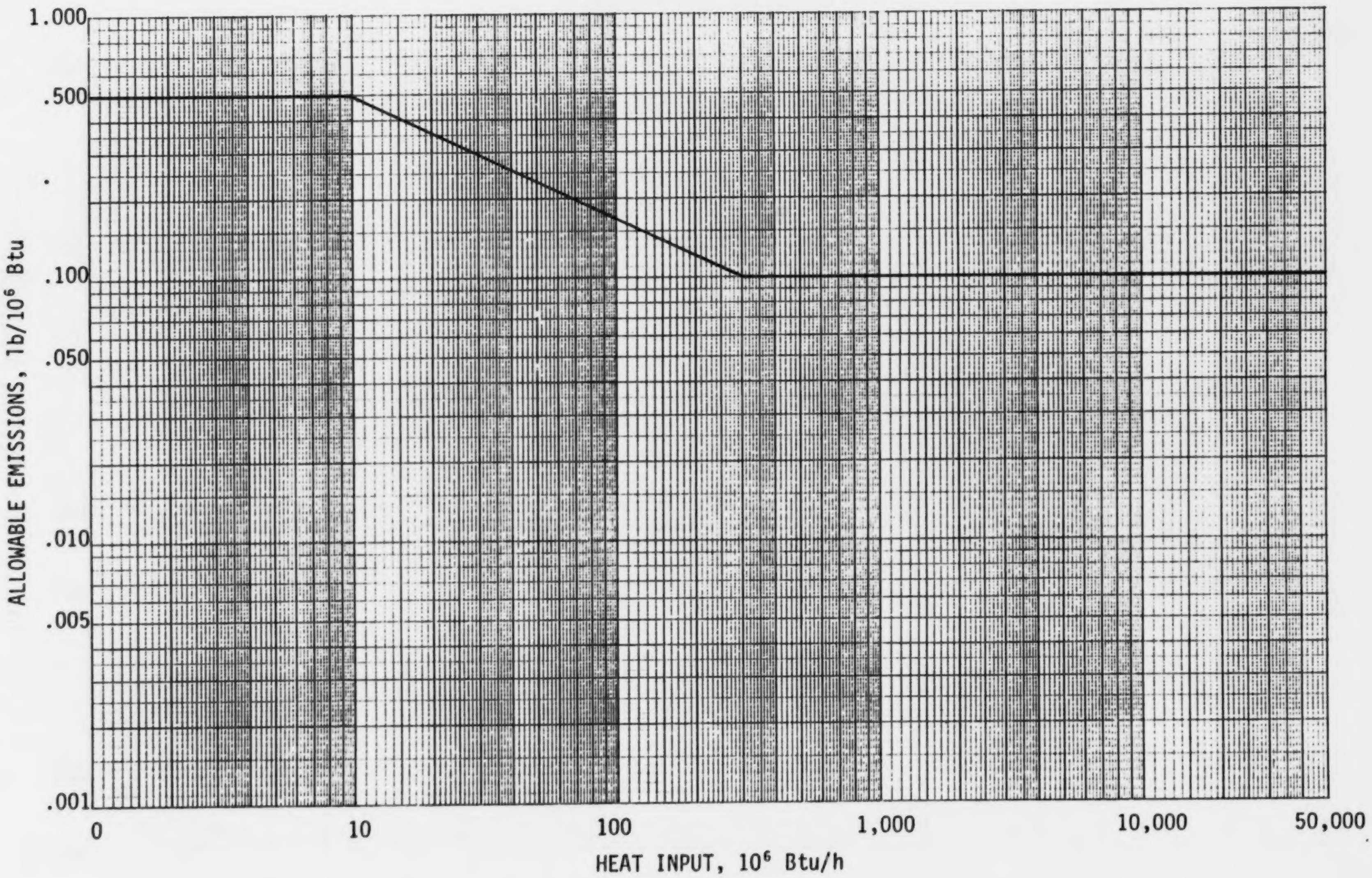
Reference Figure 1-4.



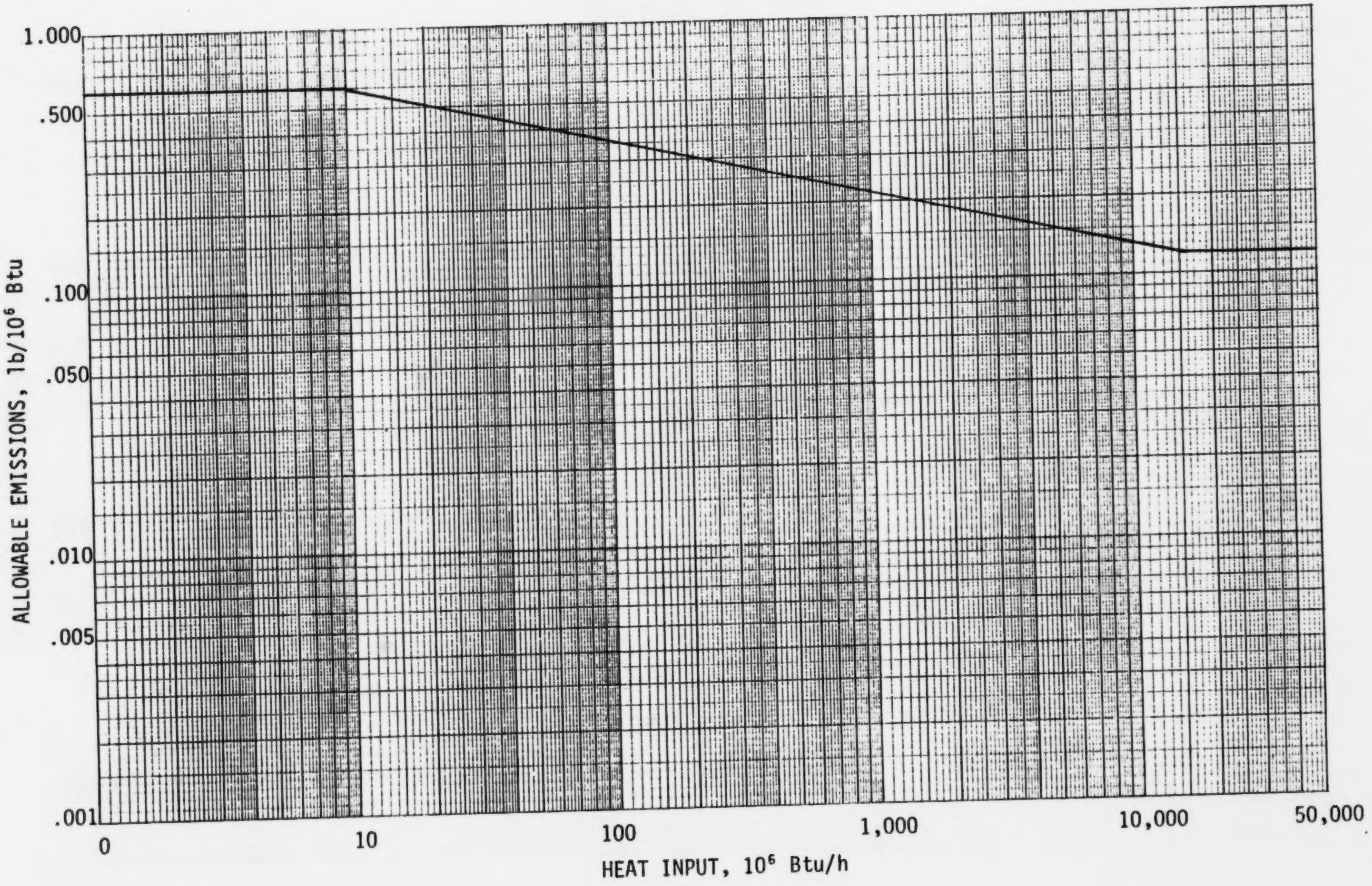
Reference Figure 1-5.



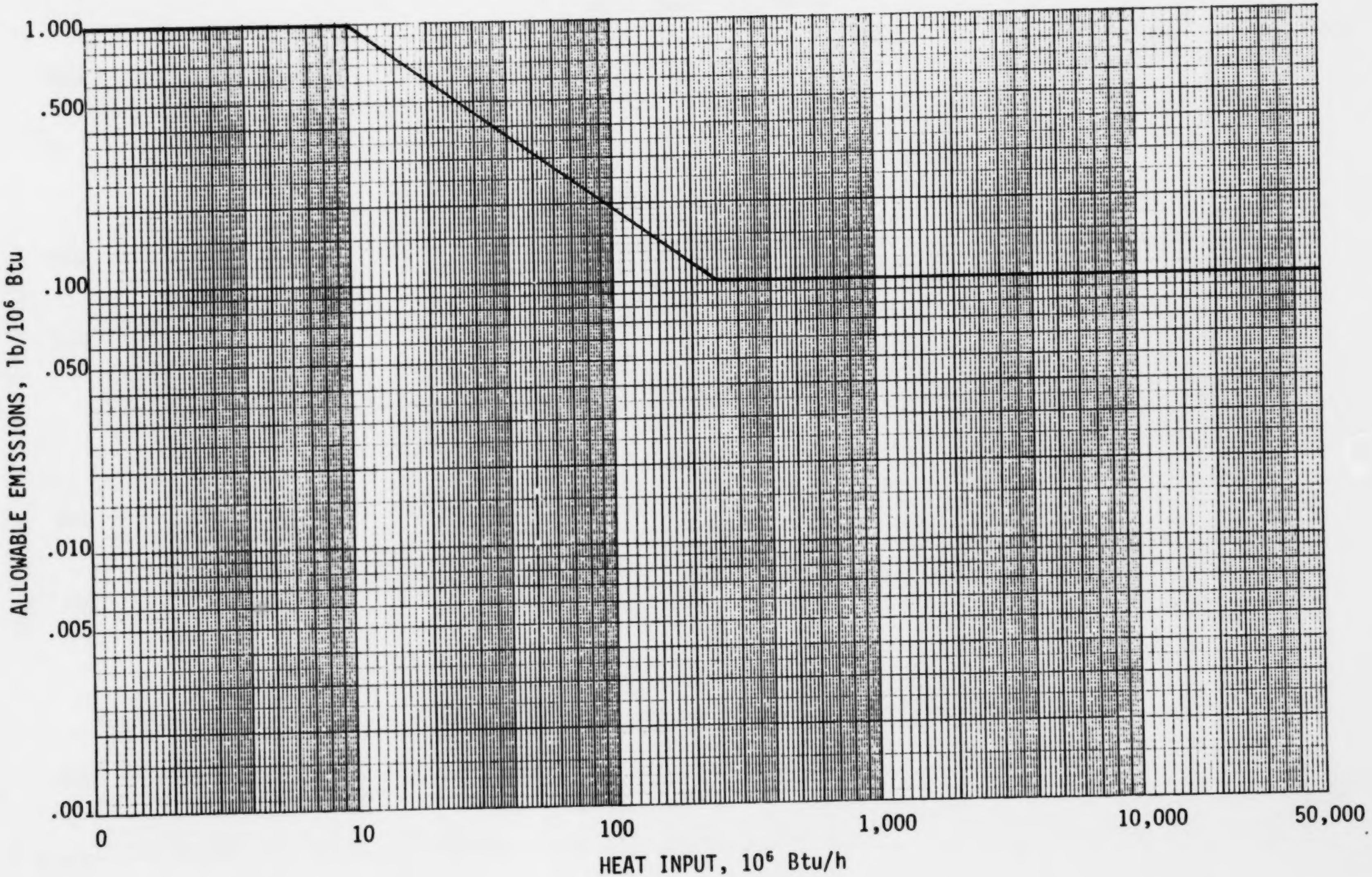
Reference Figure 1-6.



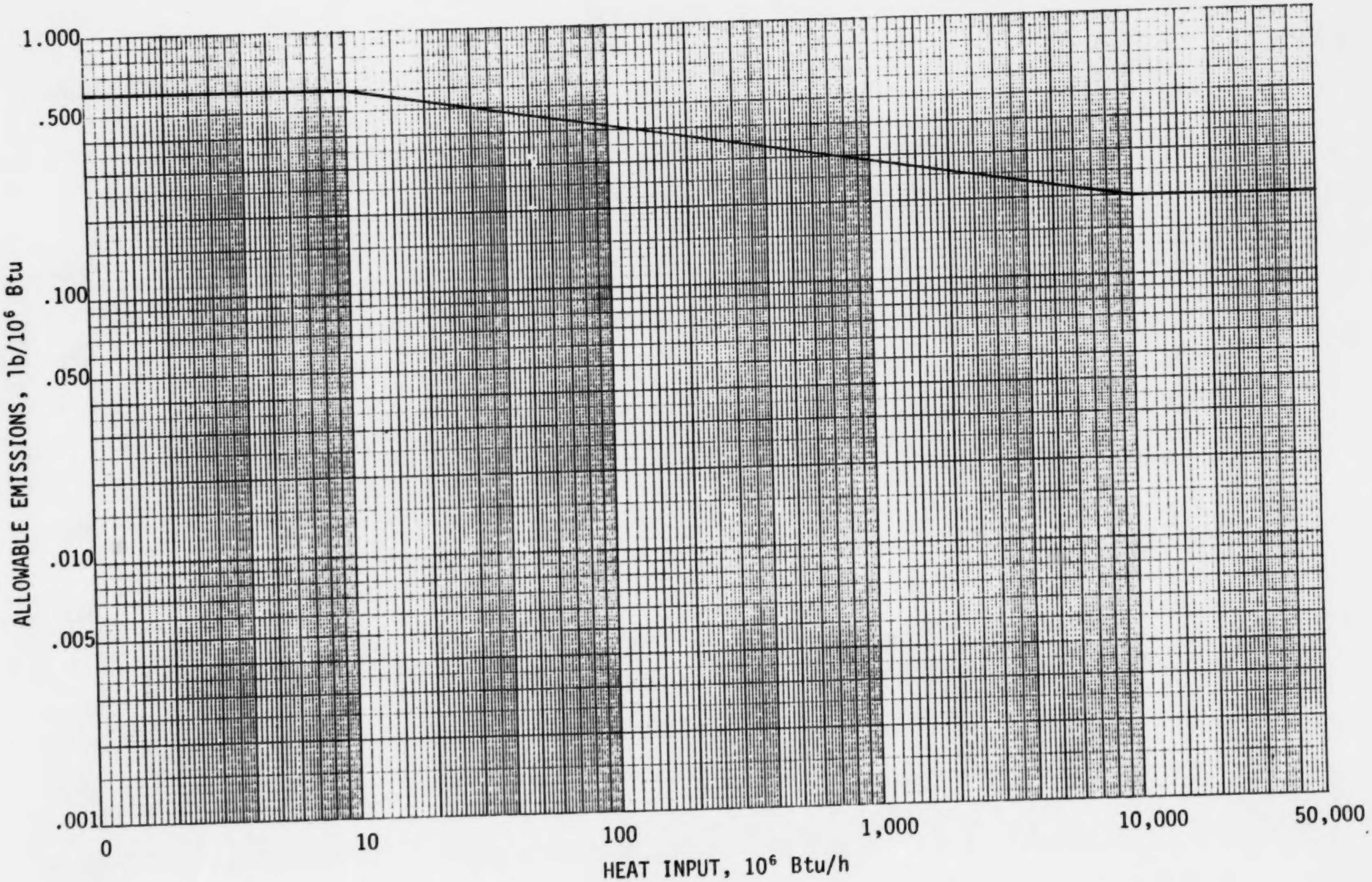
Reference Figure 1-7.



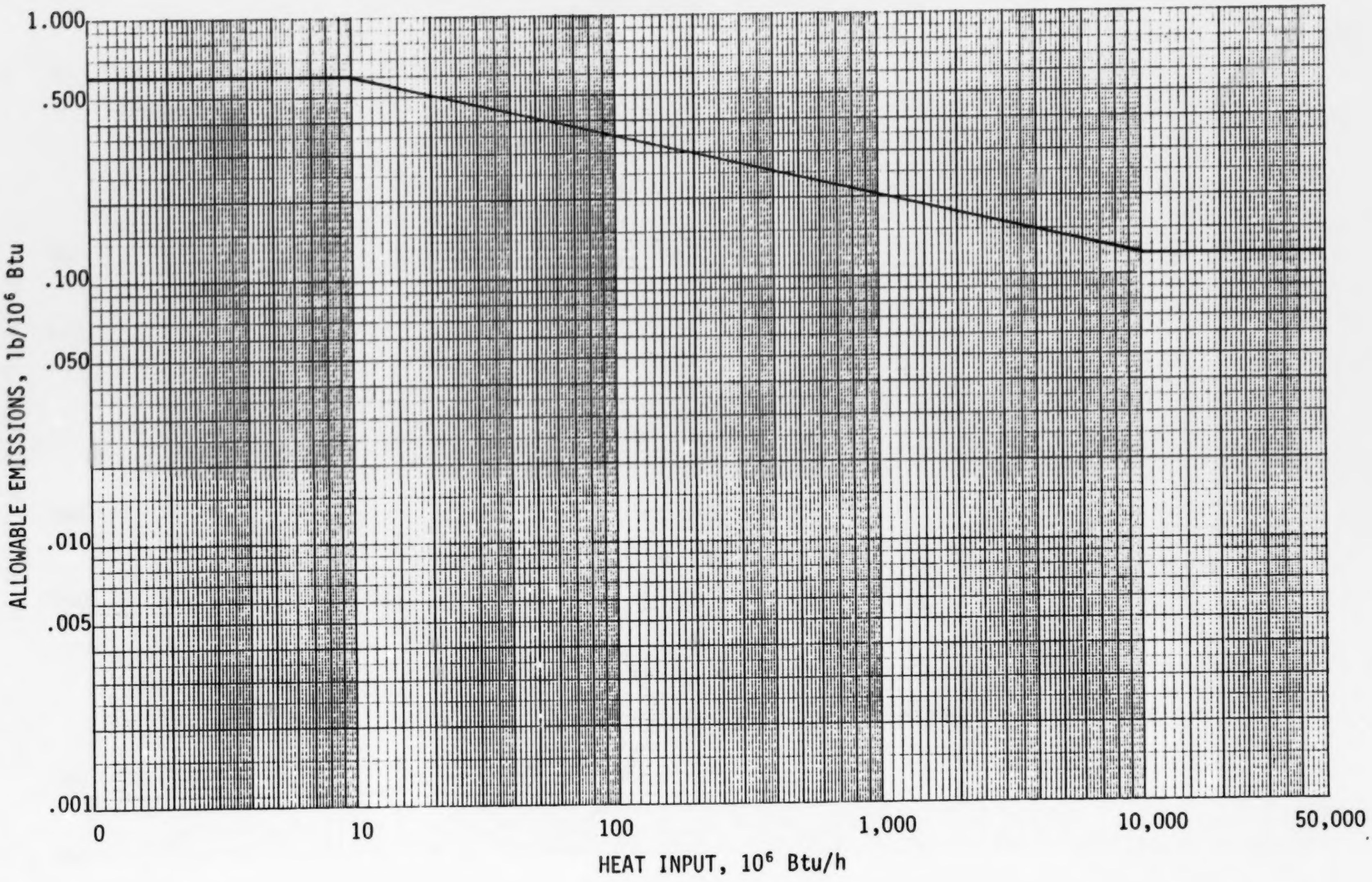
Reference Figure 1-8.



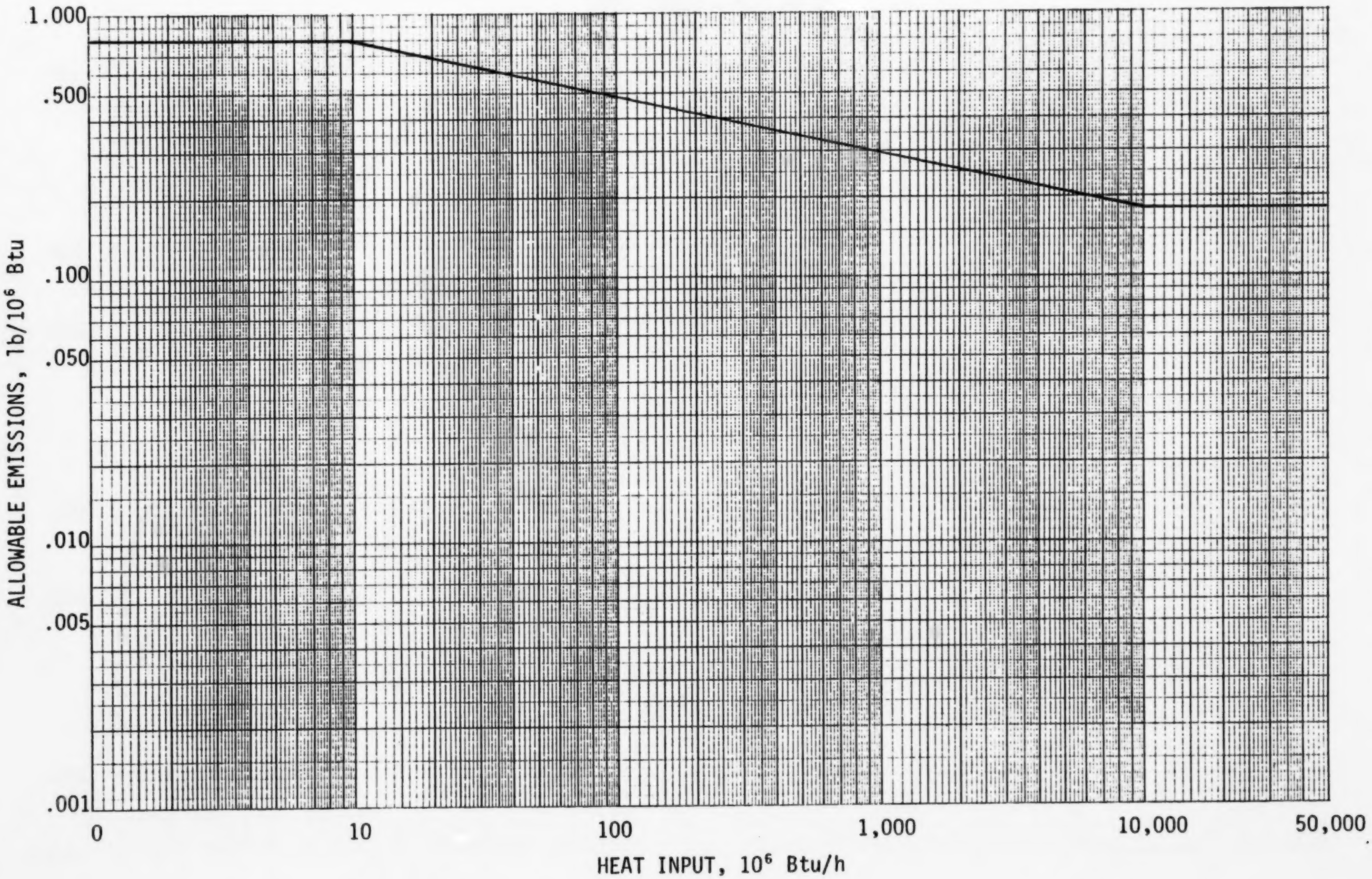
Reference Figure 1-9.



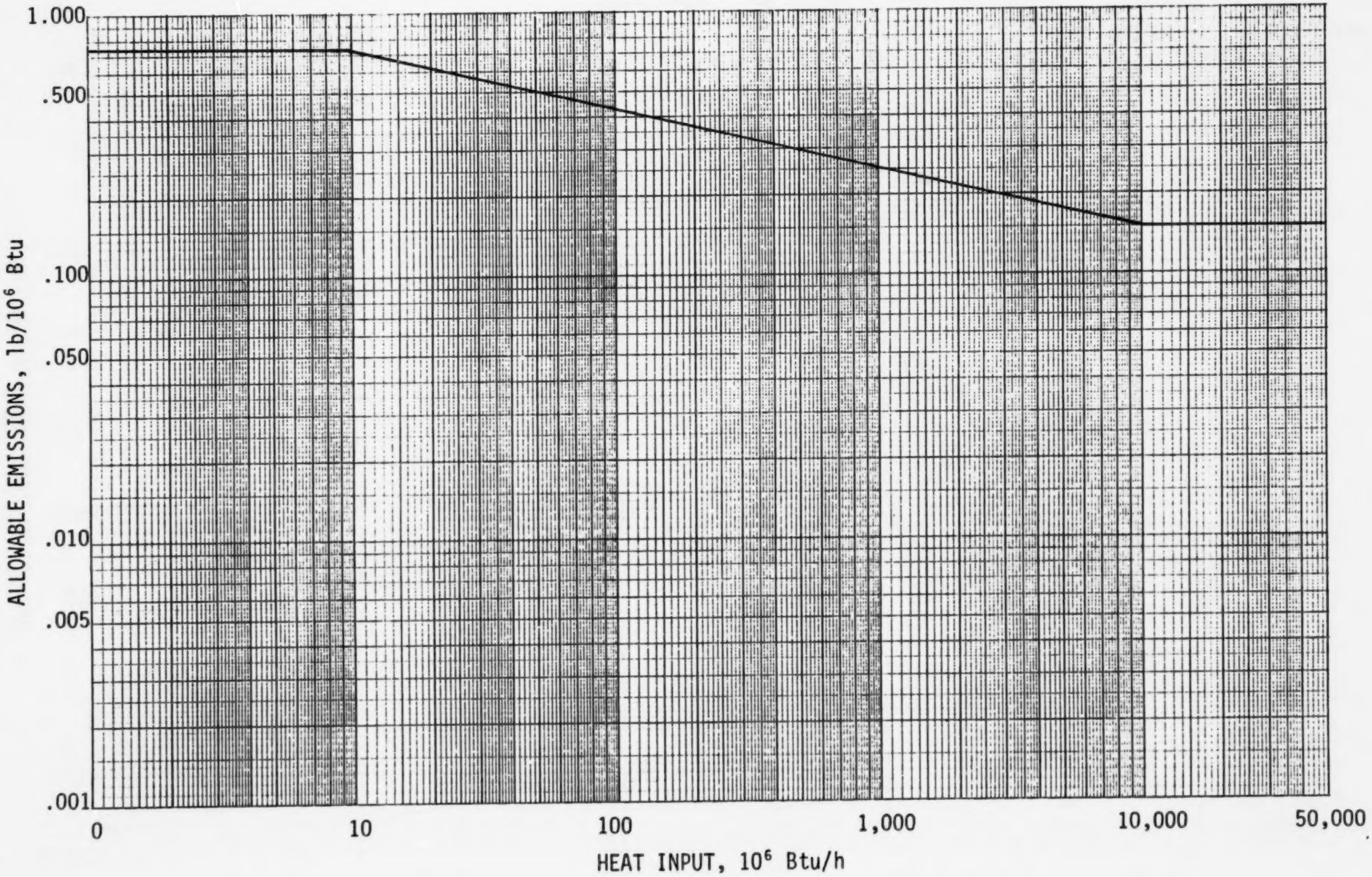
Reference Figure 1-10.



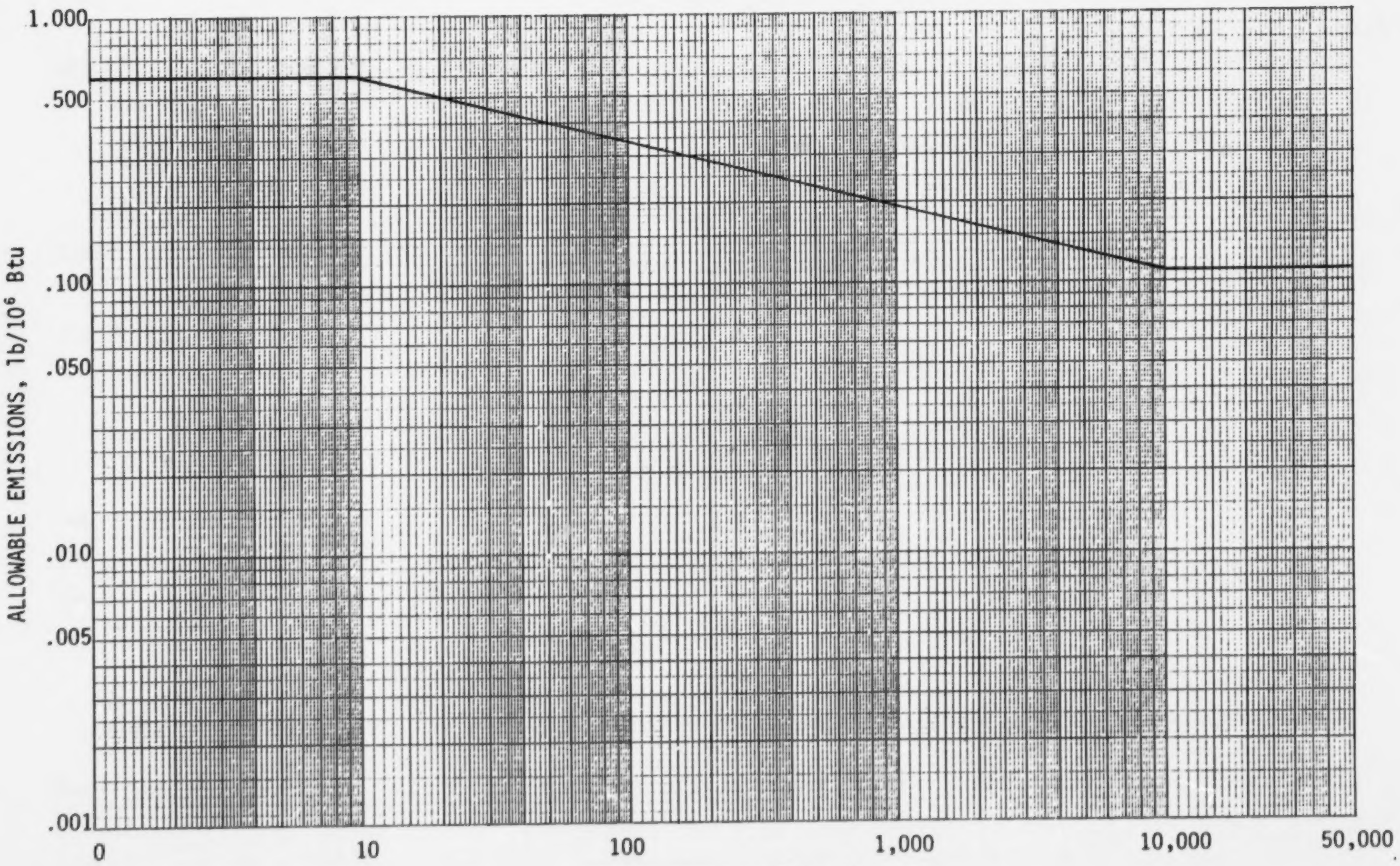
Reference Figure 1-11.



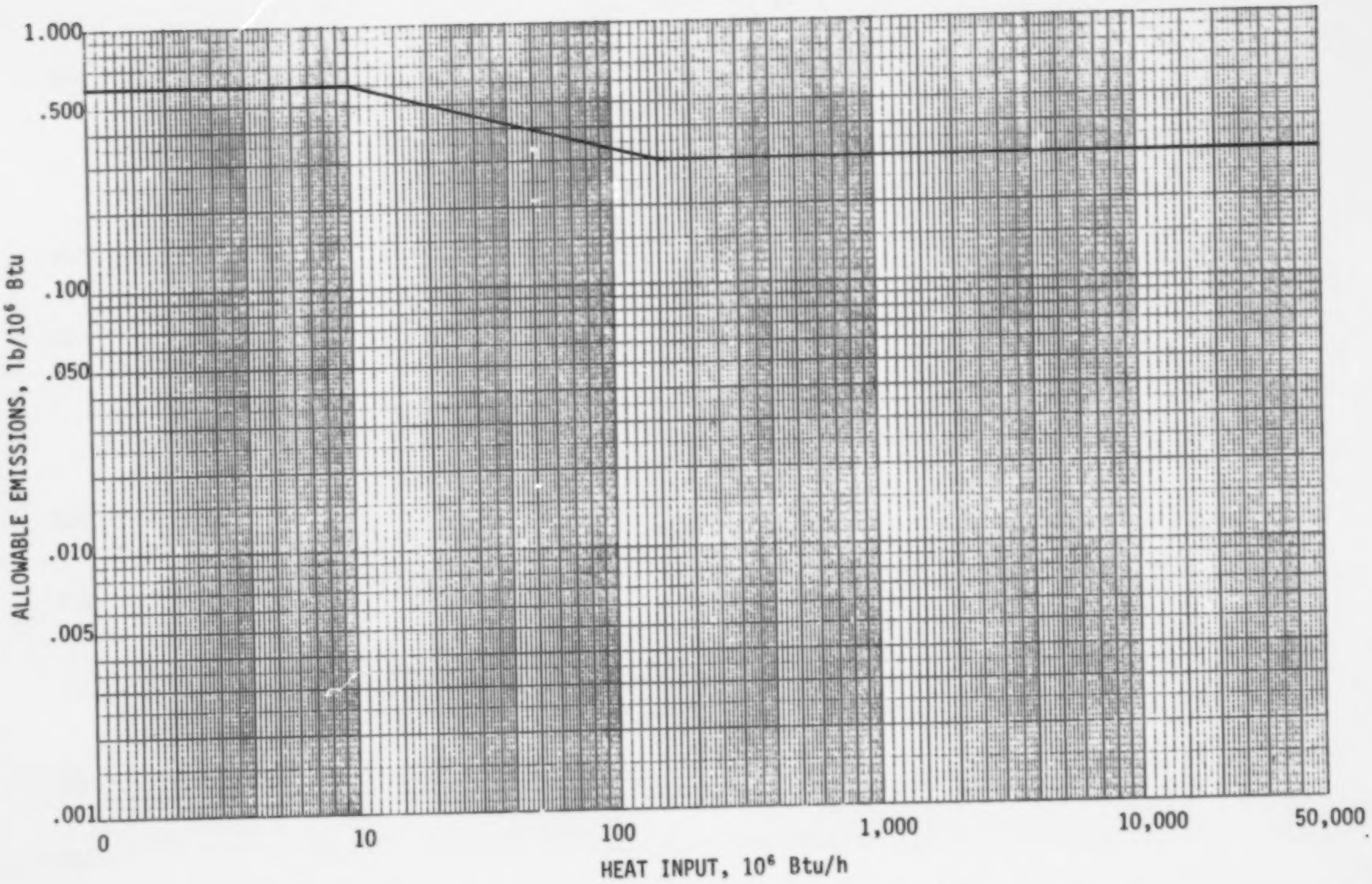
Reference Figure 1-12.



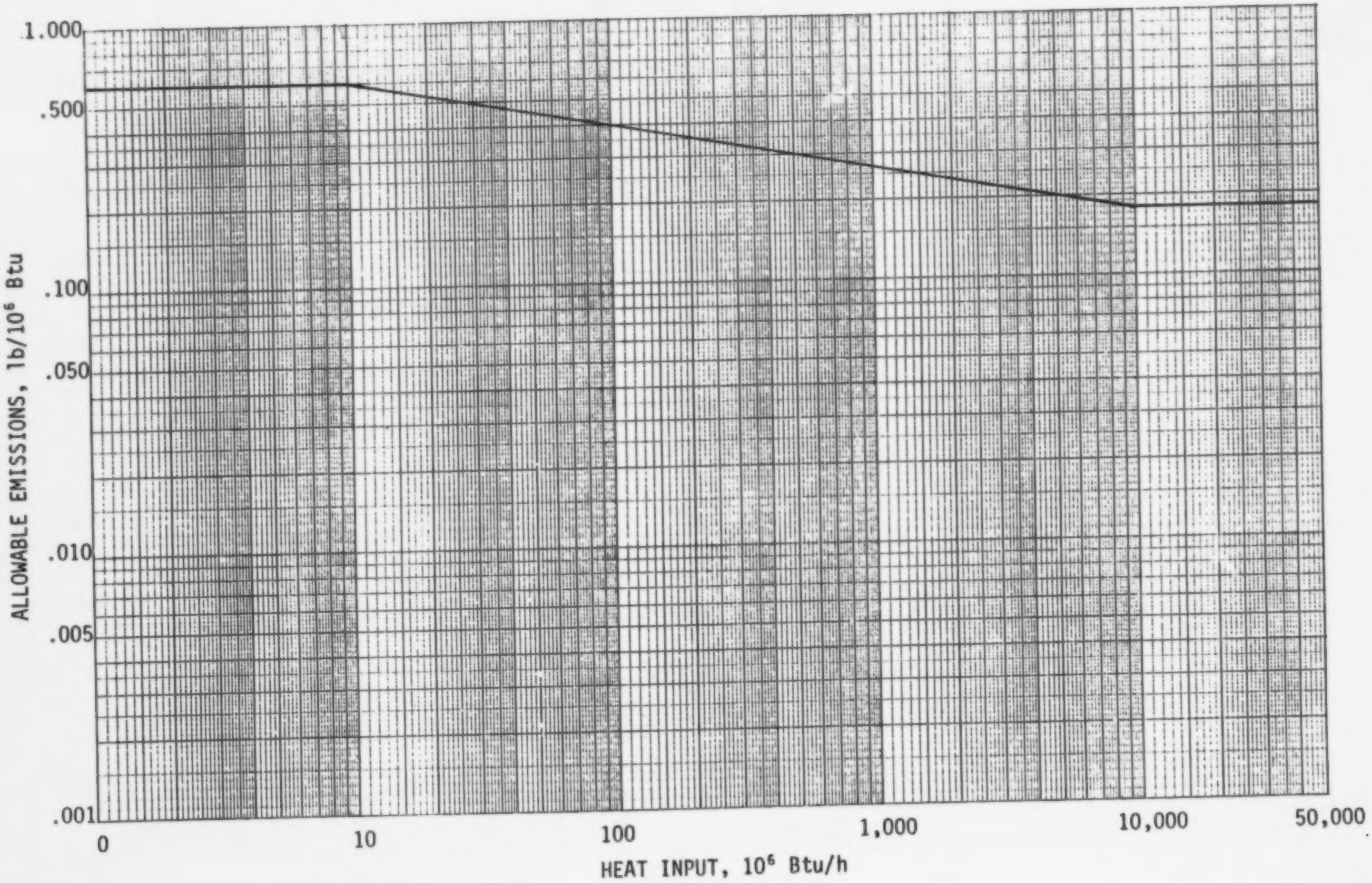
Reference Figure 1-13.



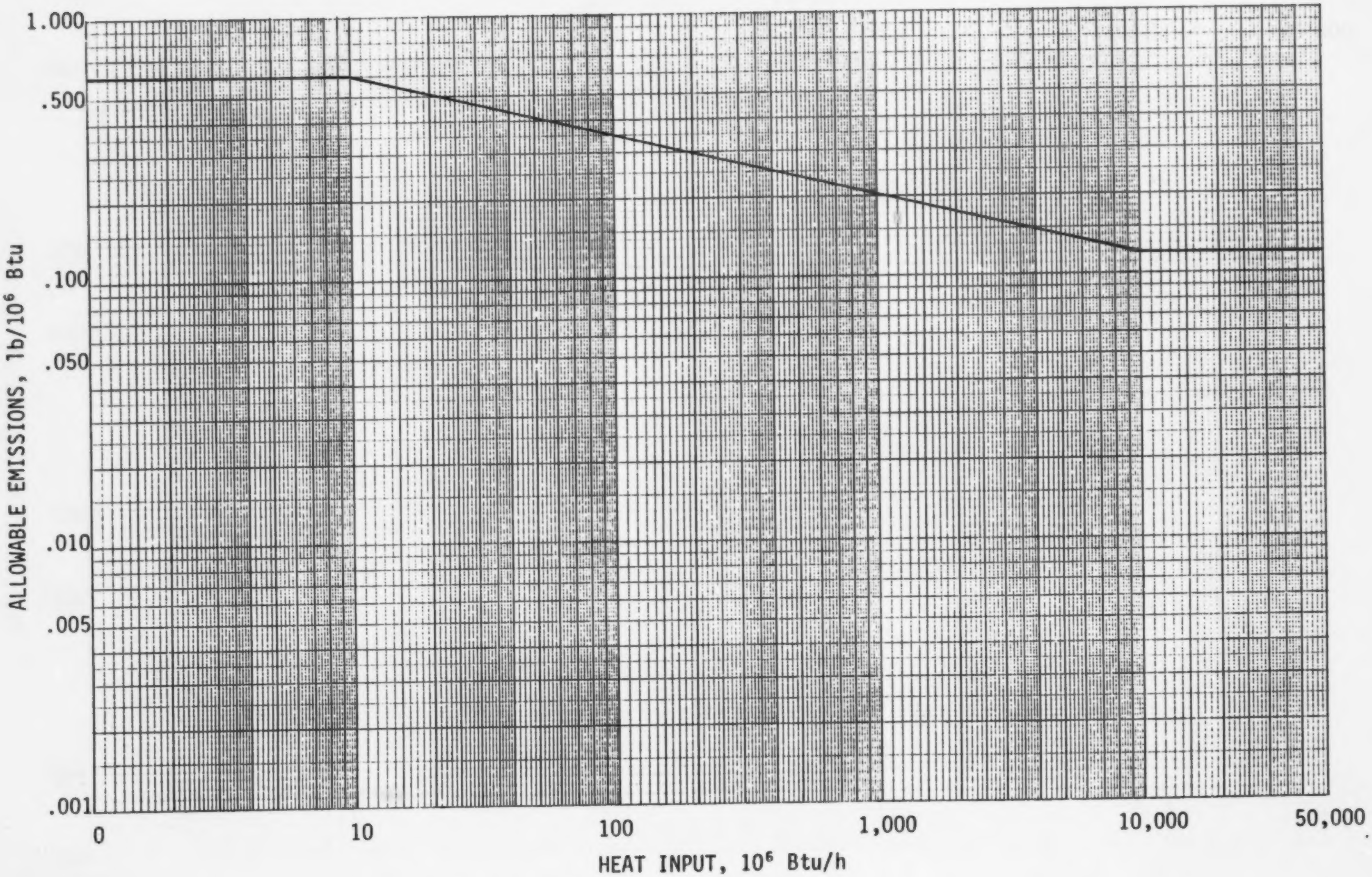
Reference Figure 1-14.



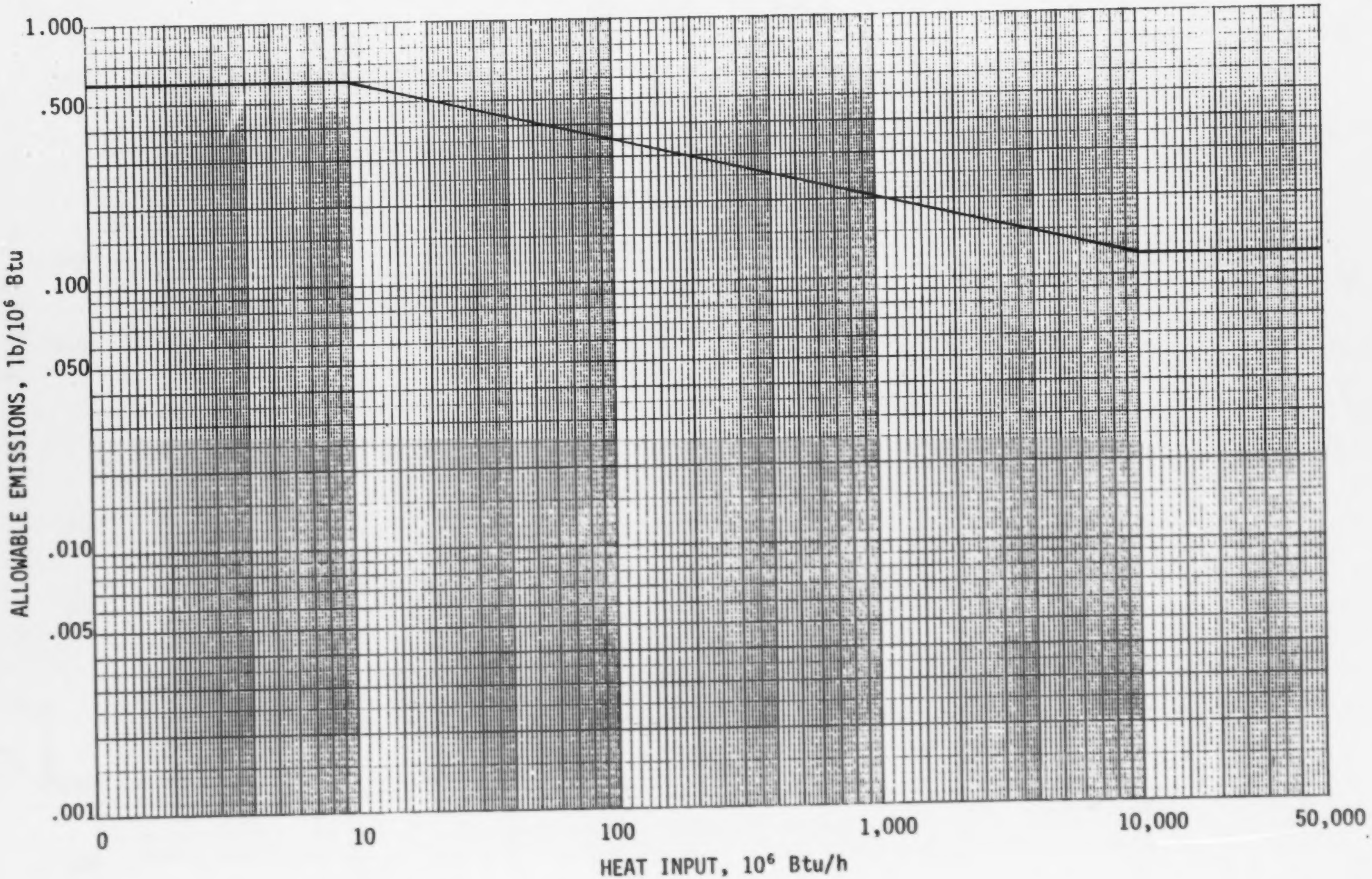
Reference Figure 1-15.



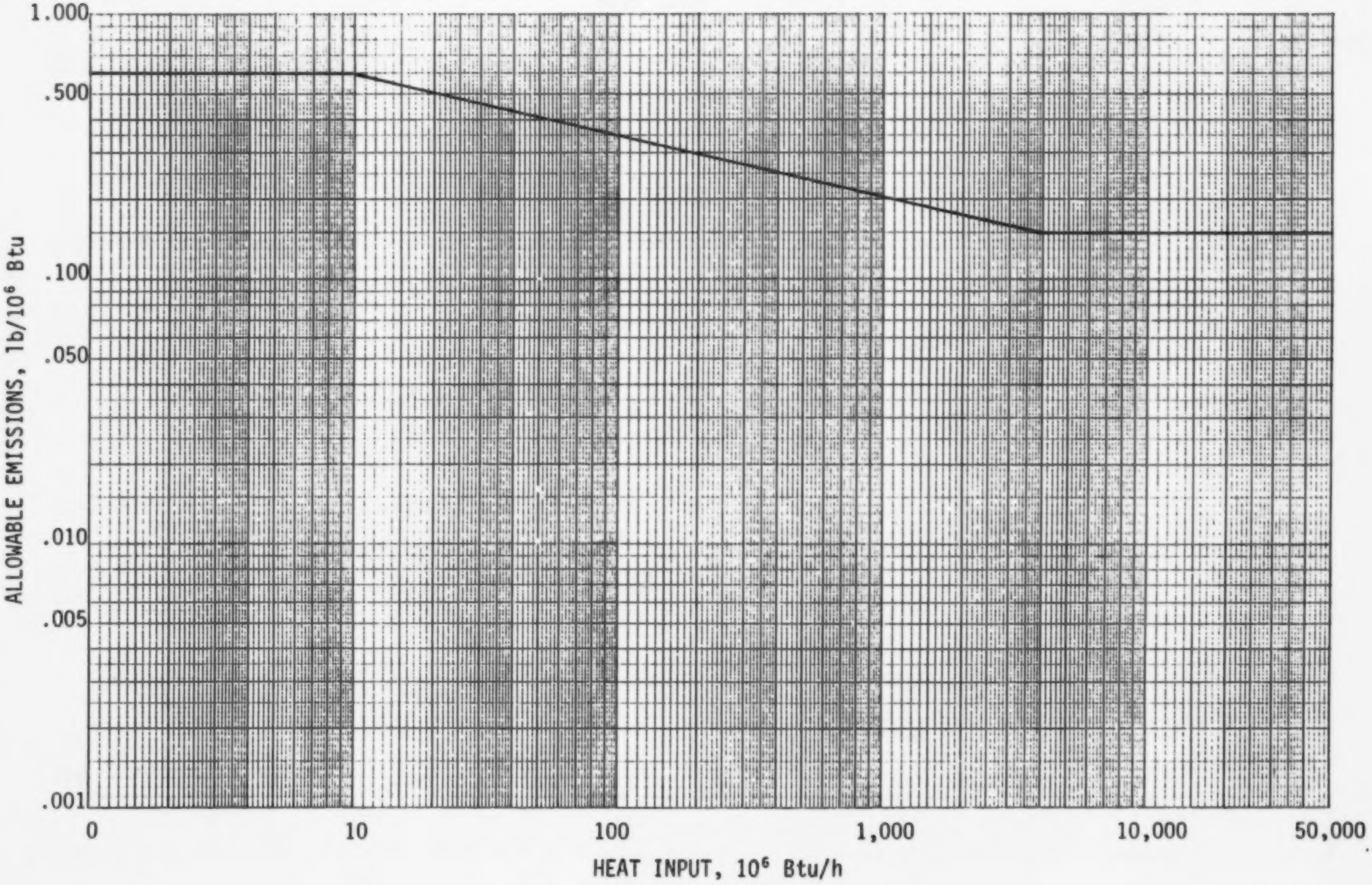
Reference Figure 1-16.



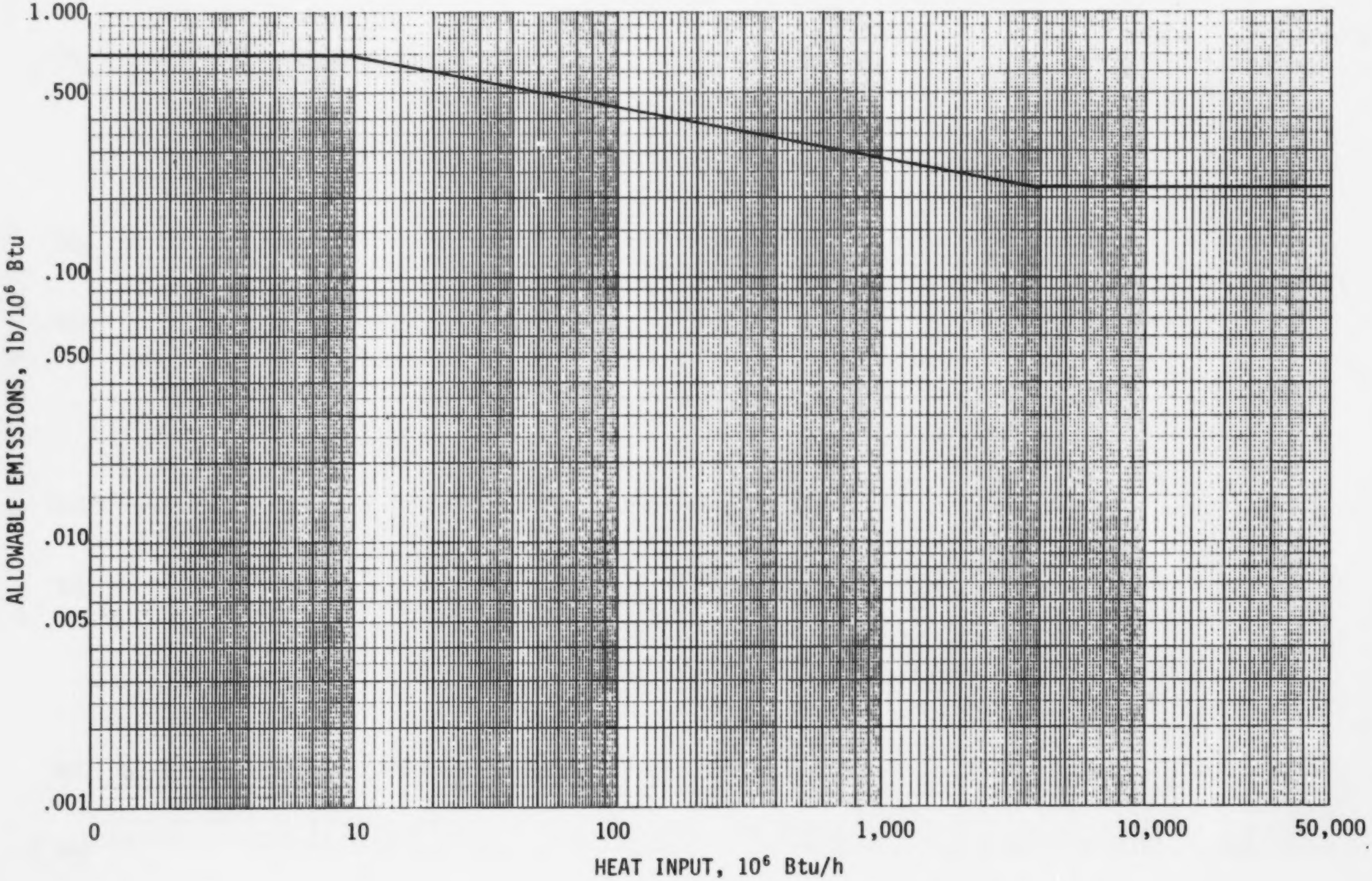
Reference Figure 1-17.



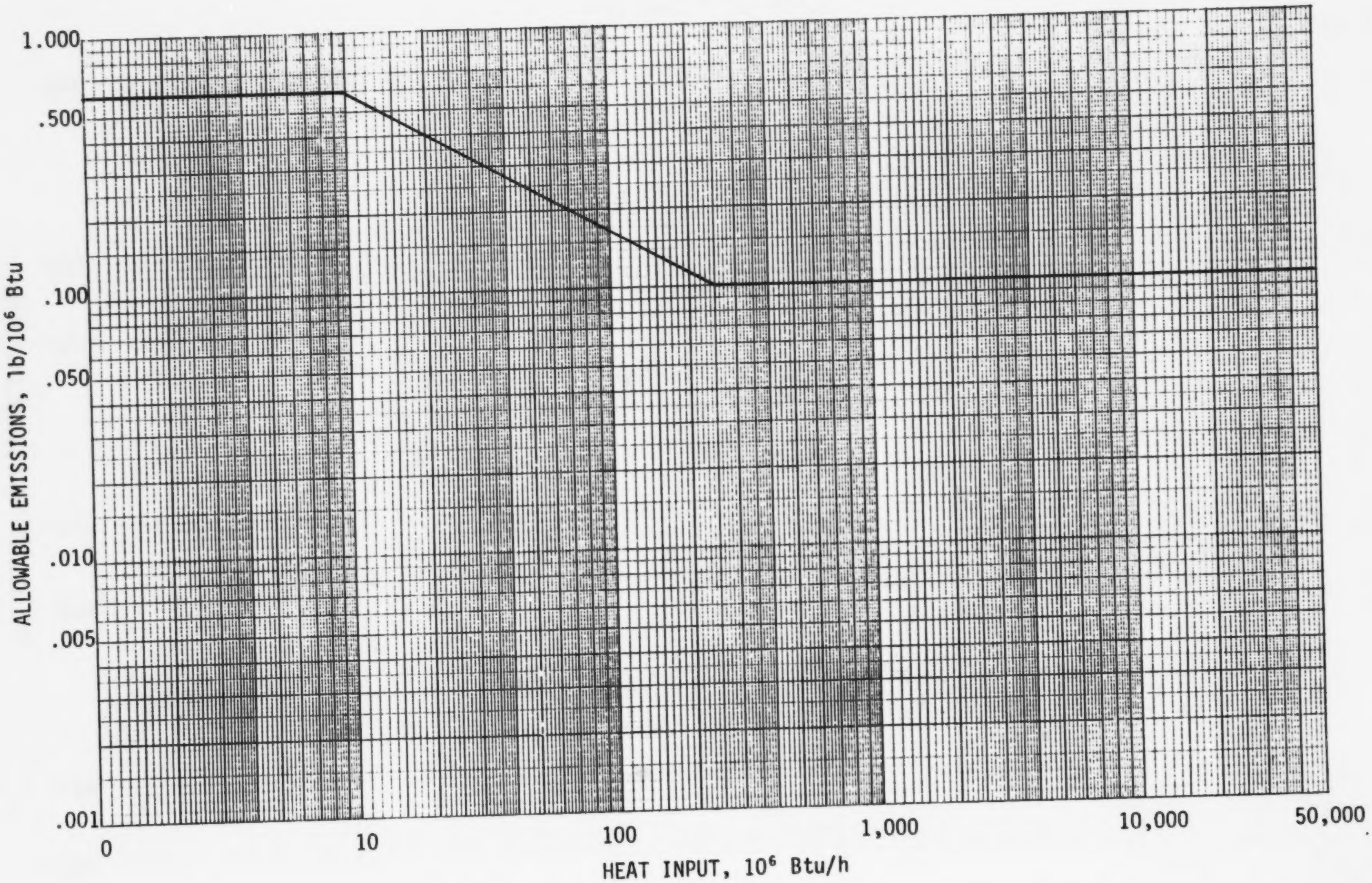
Reference Figure 1-18.



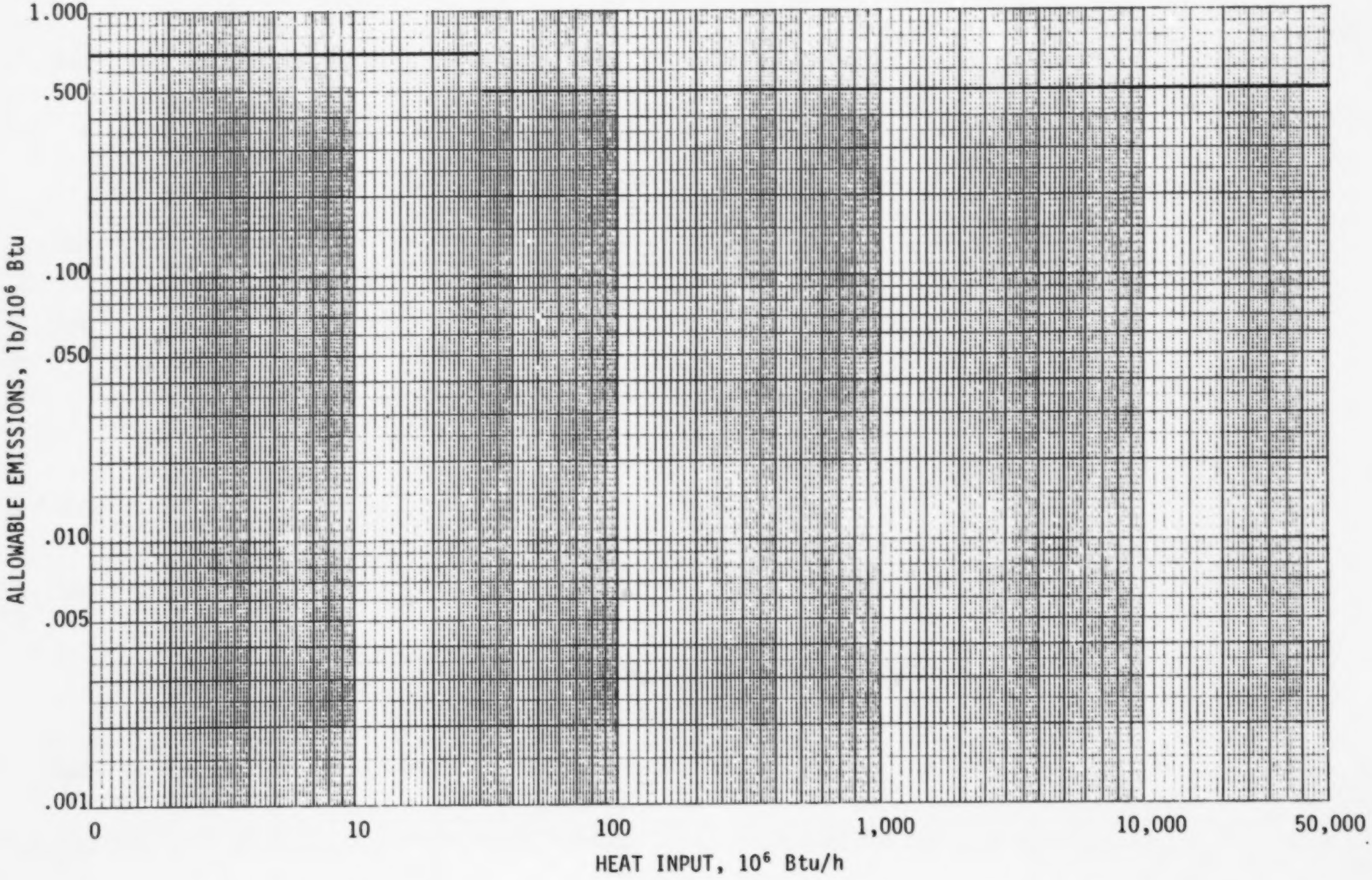
Reference Figure 1-19.



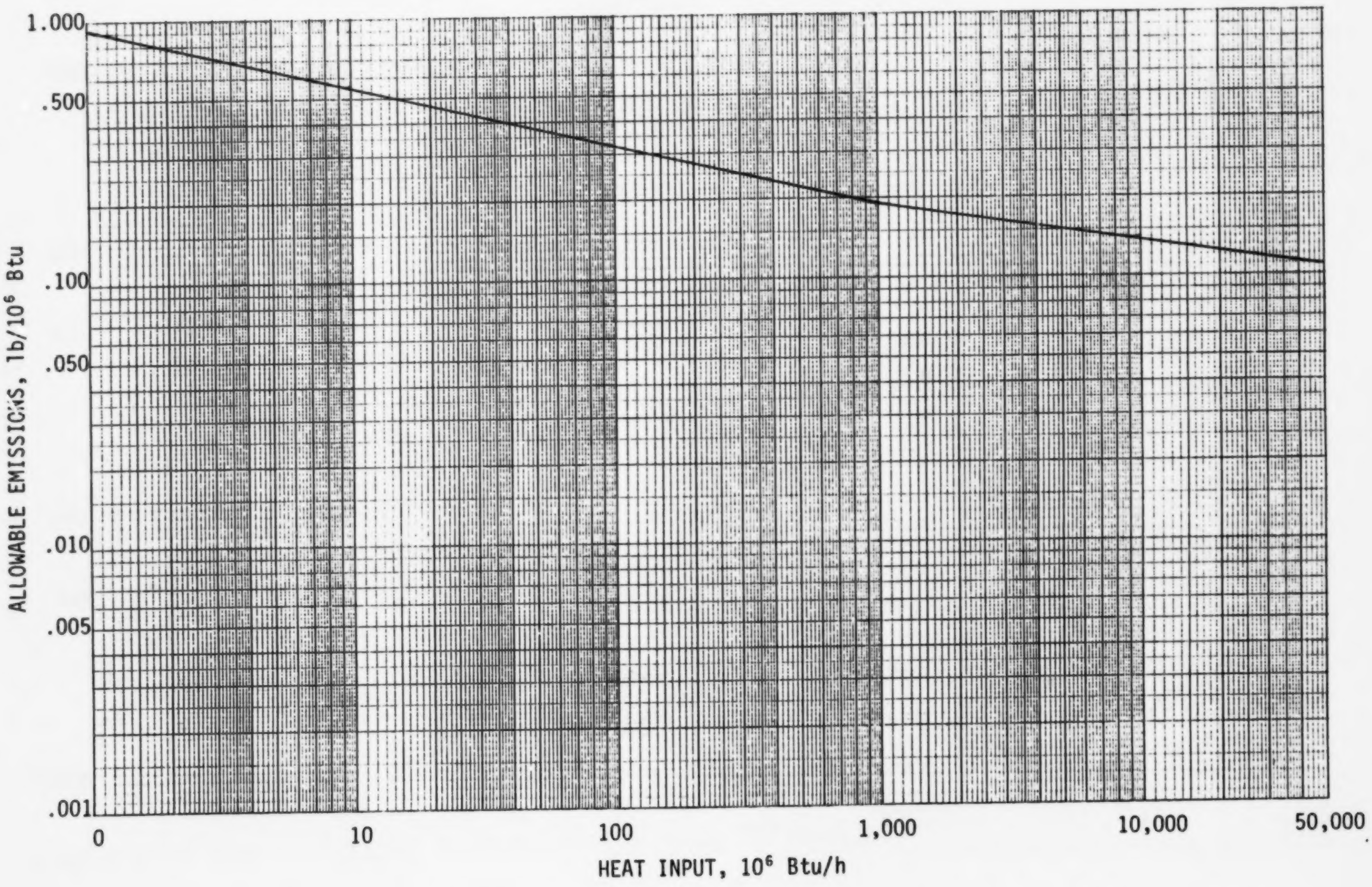
Reference Figure 1-20.



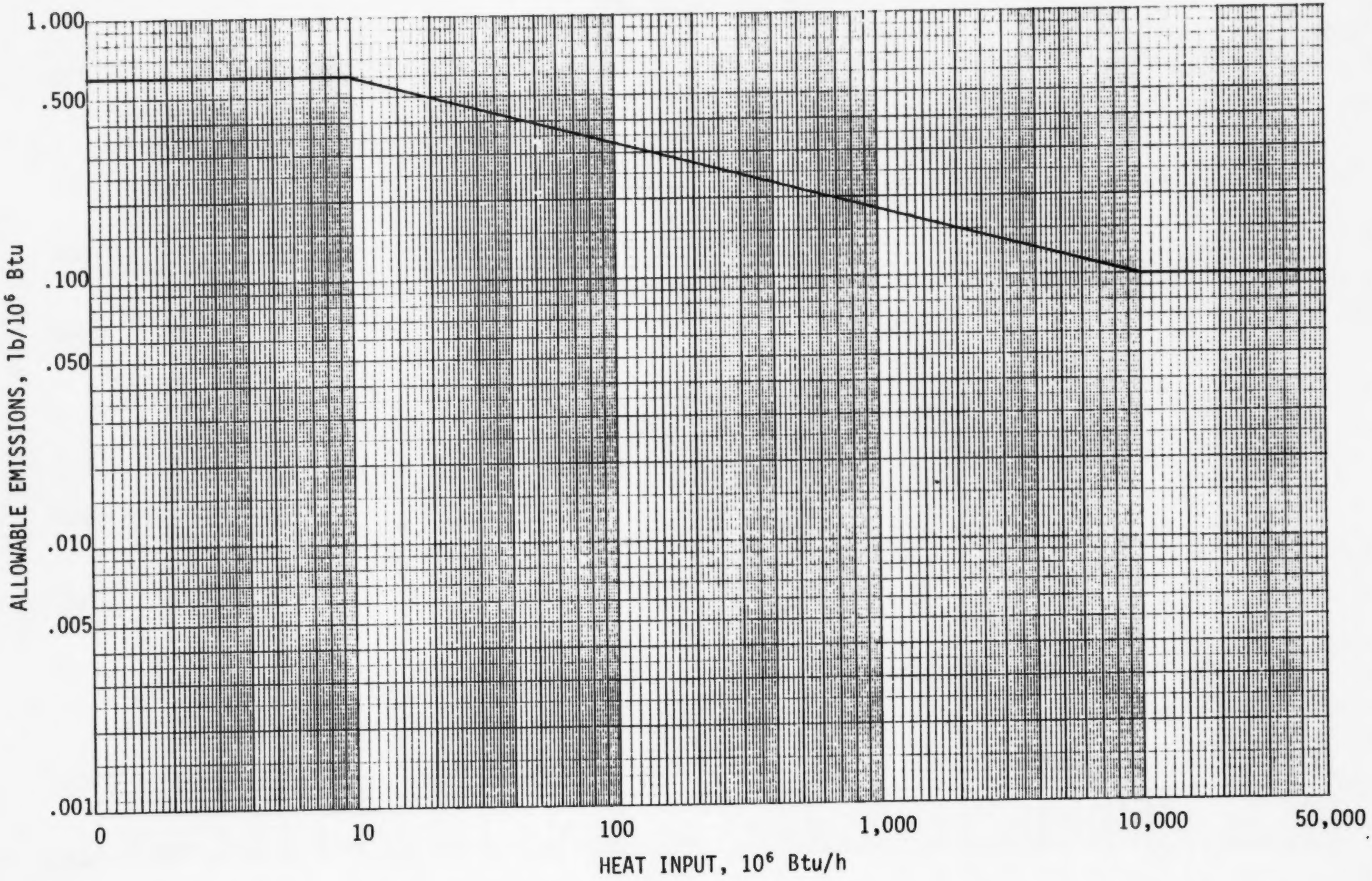
Reference Figure 1-21.



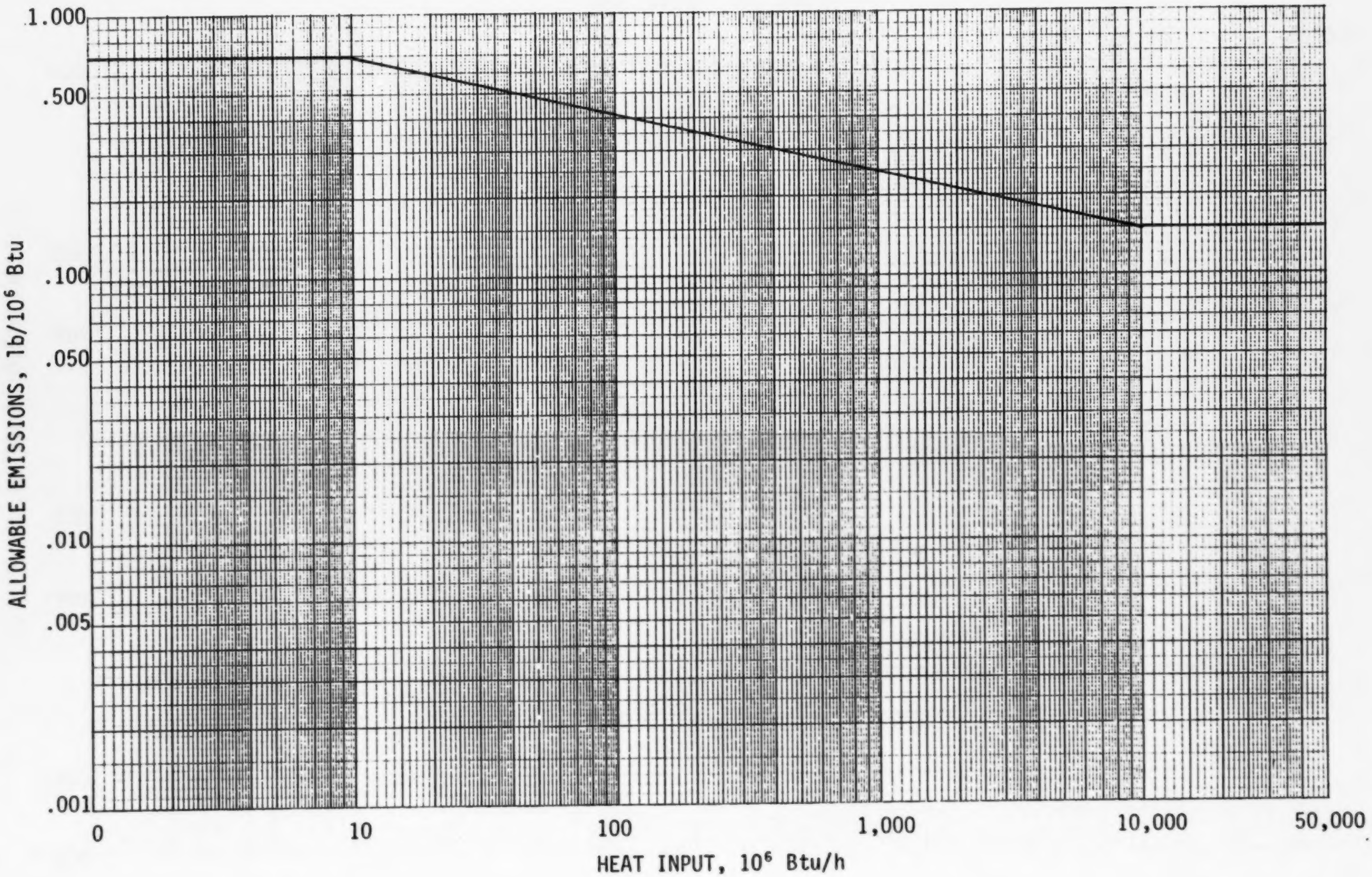
Reference Figure 1-22.



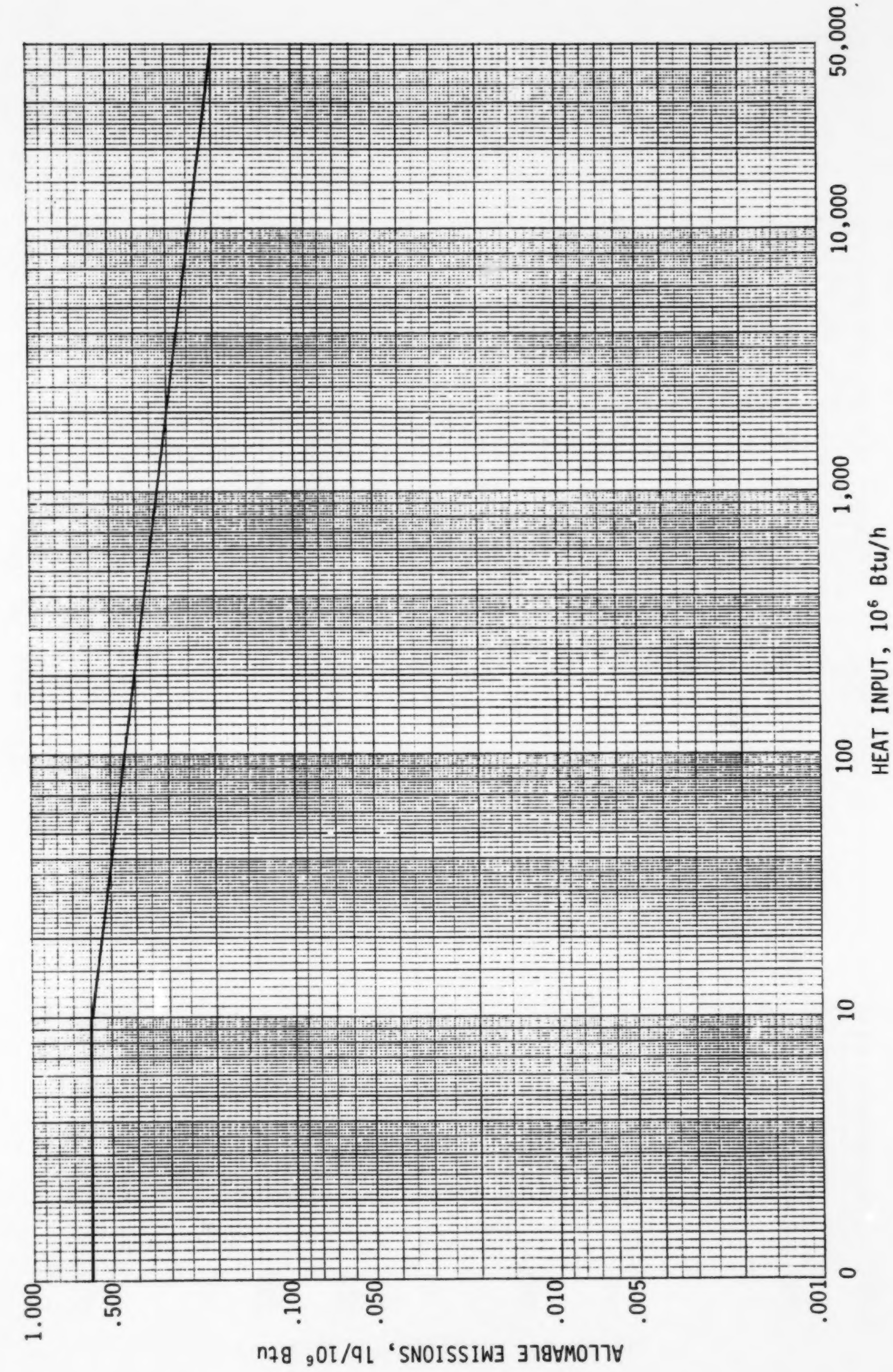
Reference Figure 1-23.



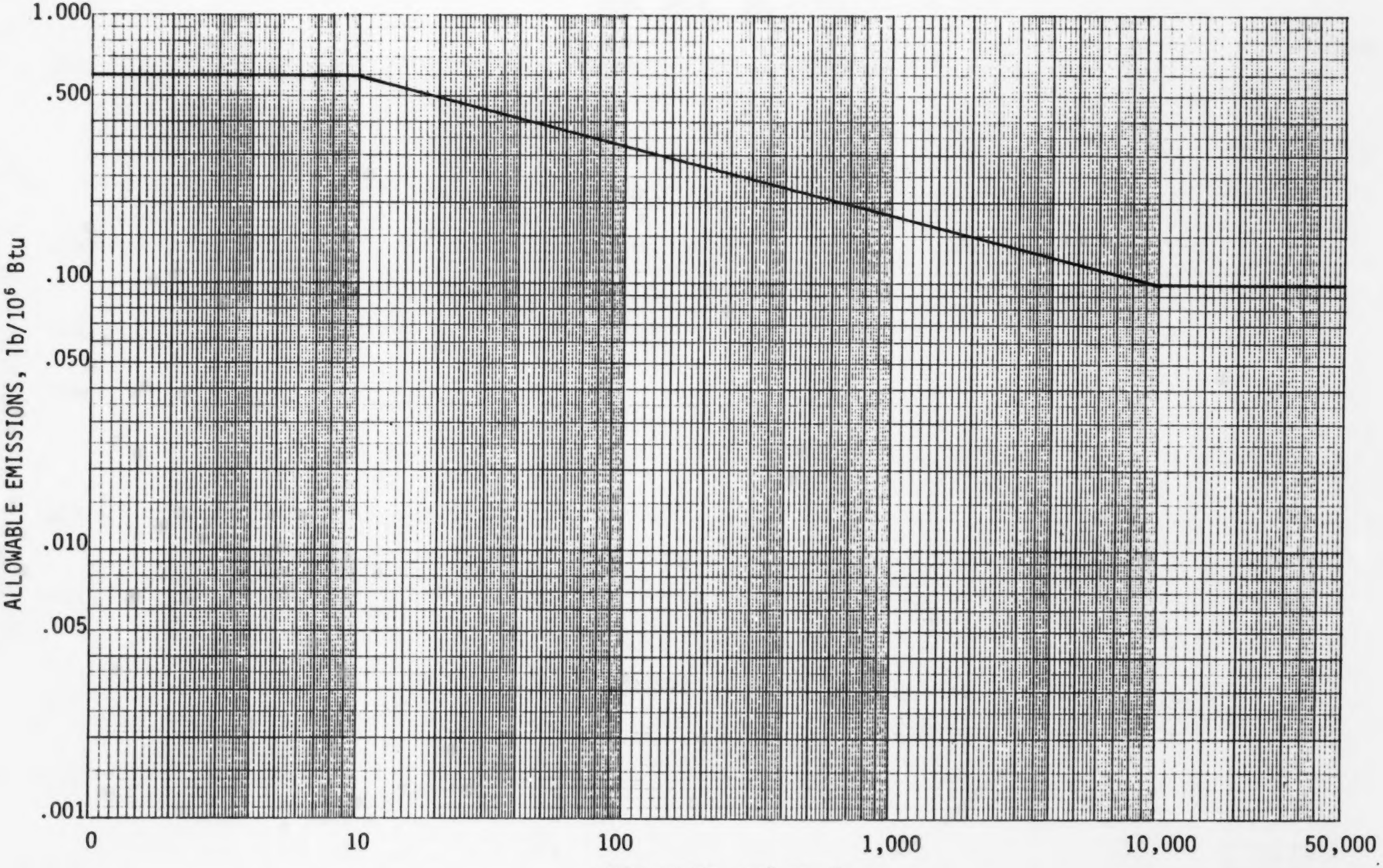
Reference Figure 1-24.



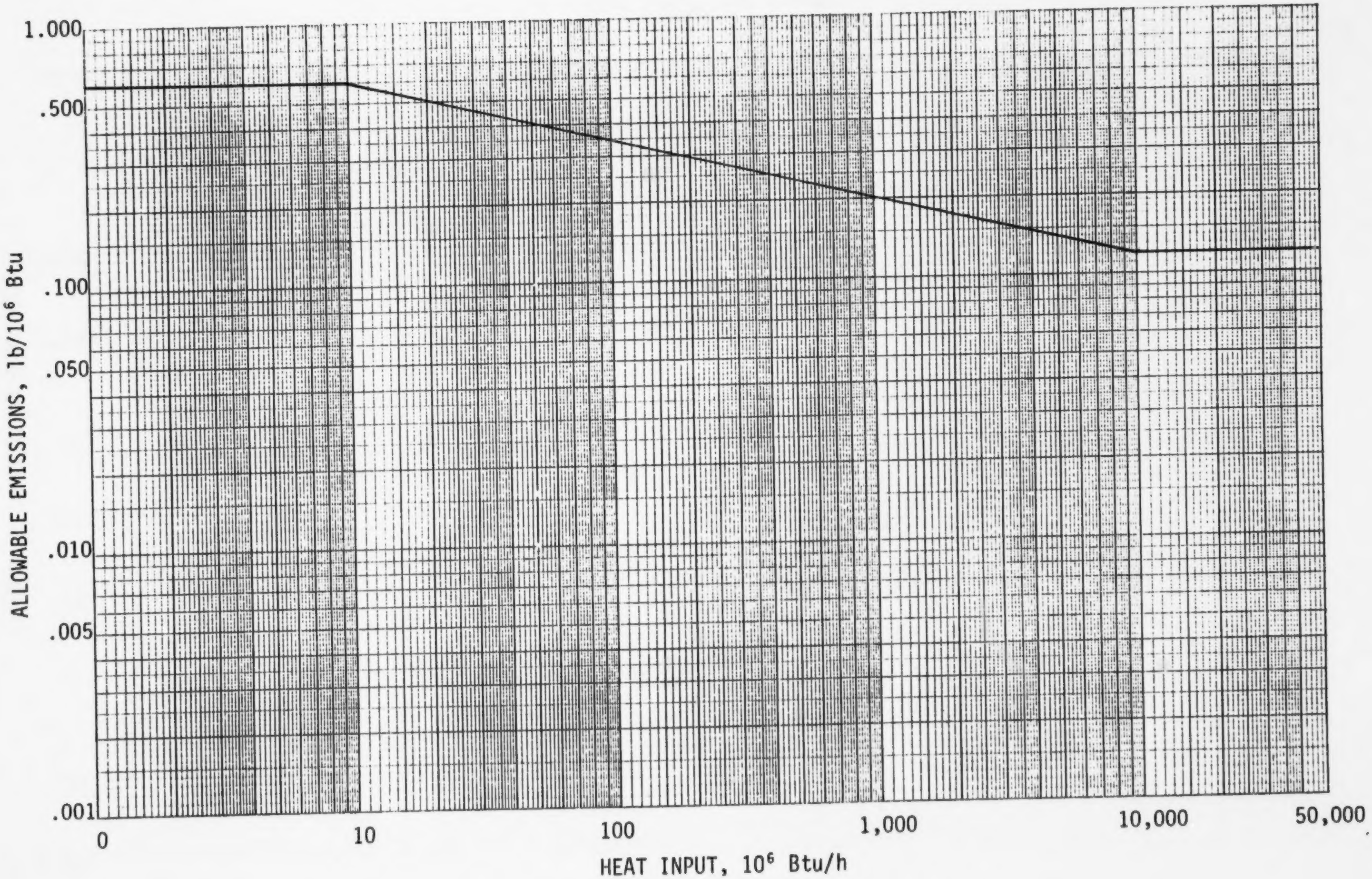
Reference Figure 1-25.



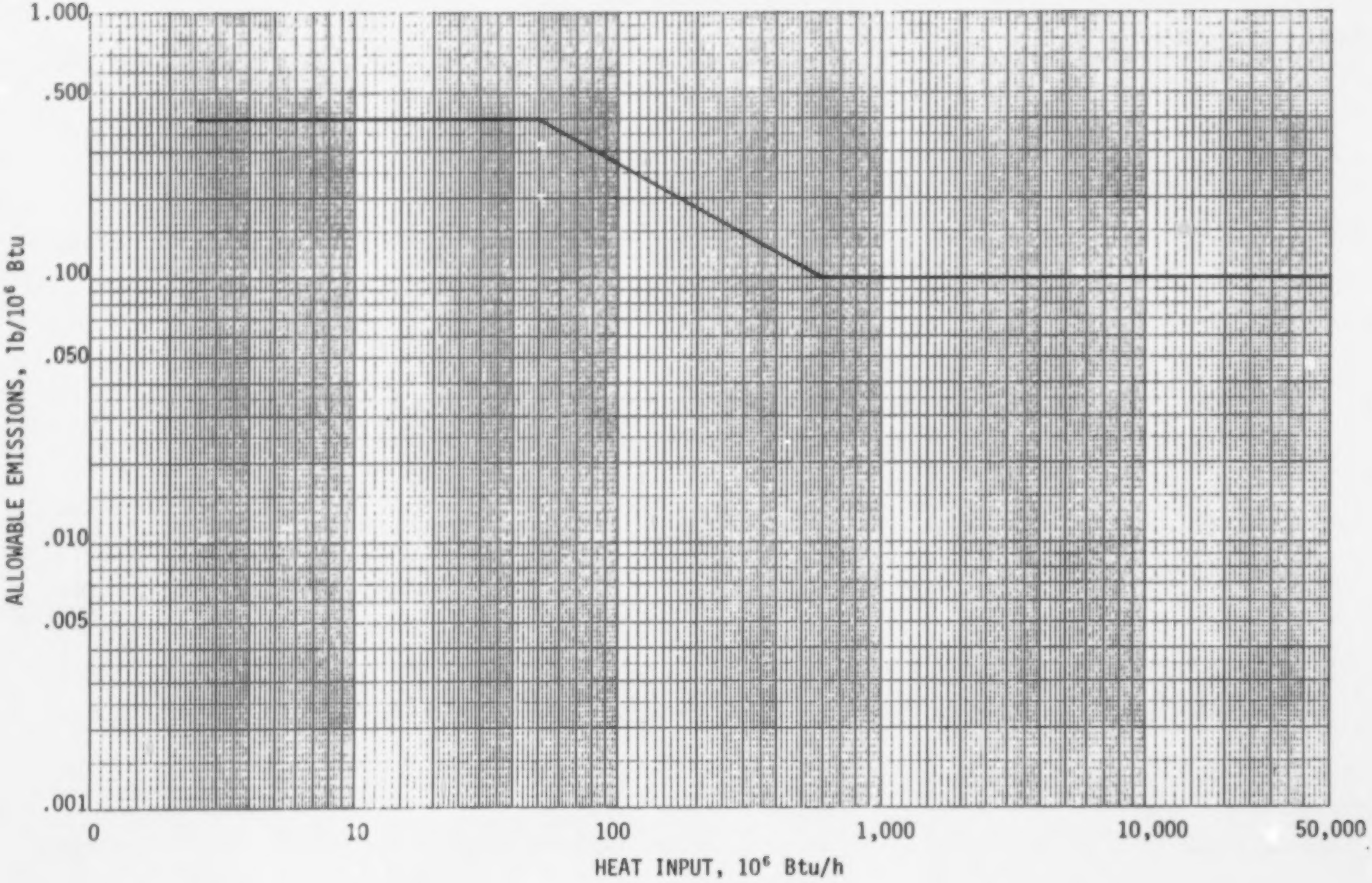
Reference Figure 1-26.



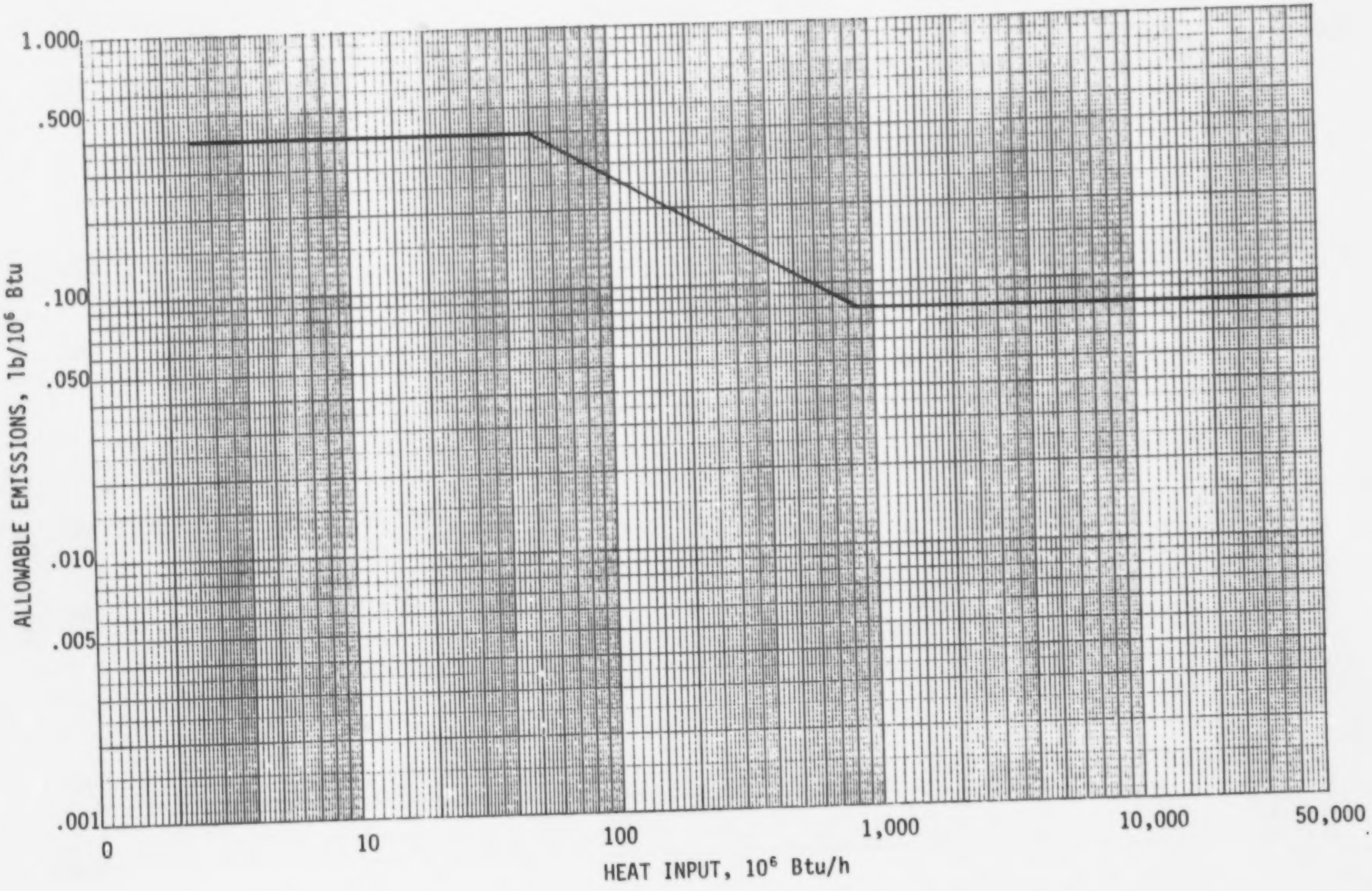
Reference Figure 1-27.



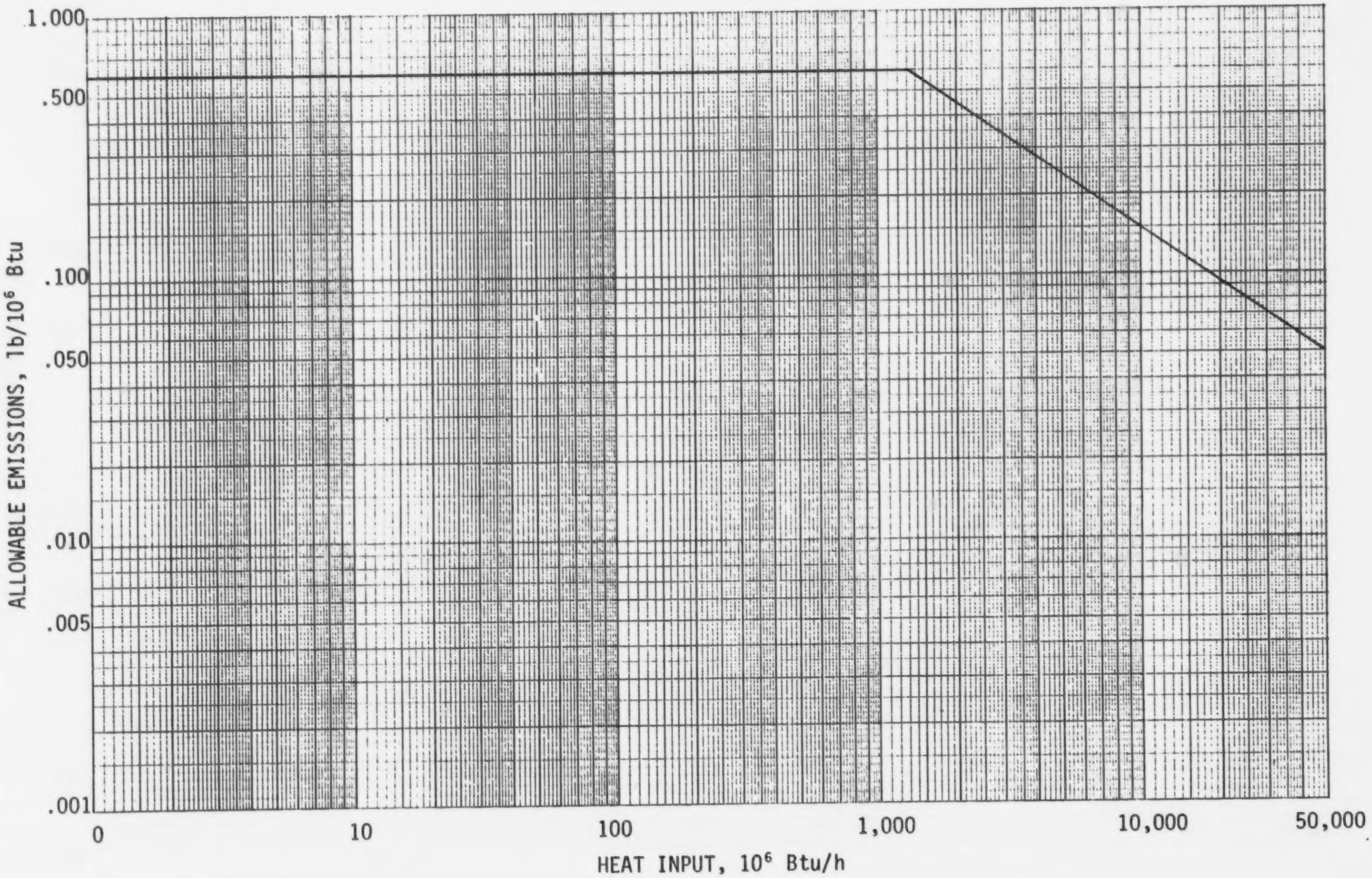
Reference Figure 1-28.



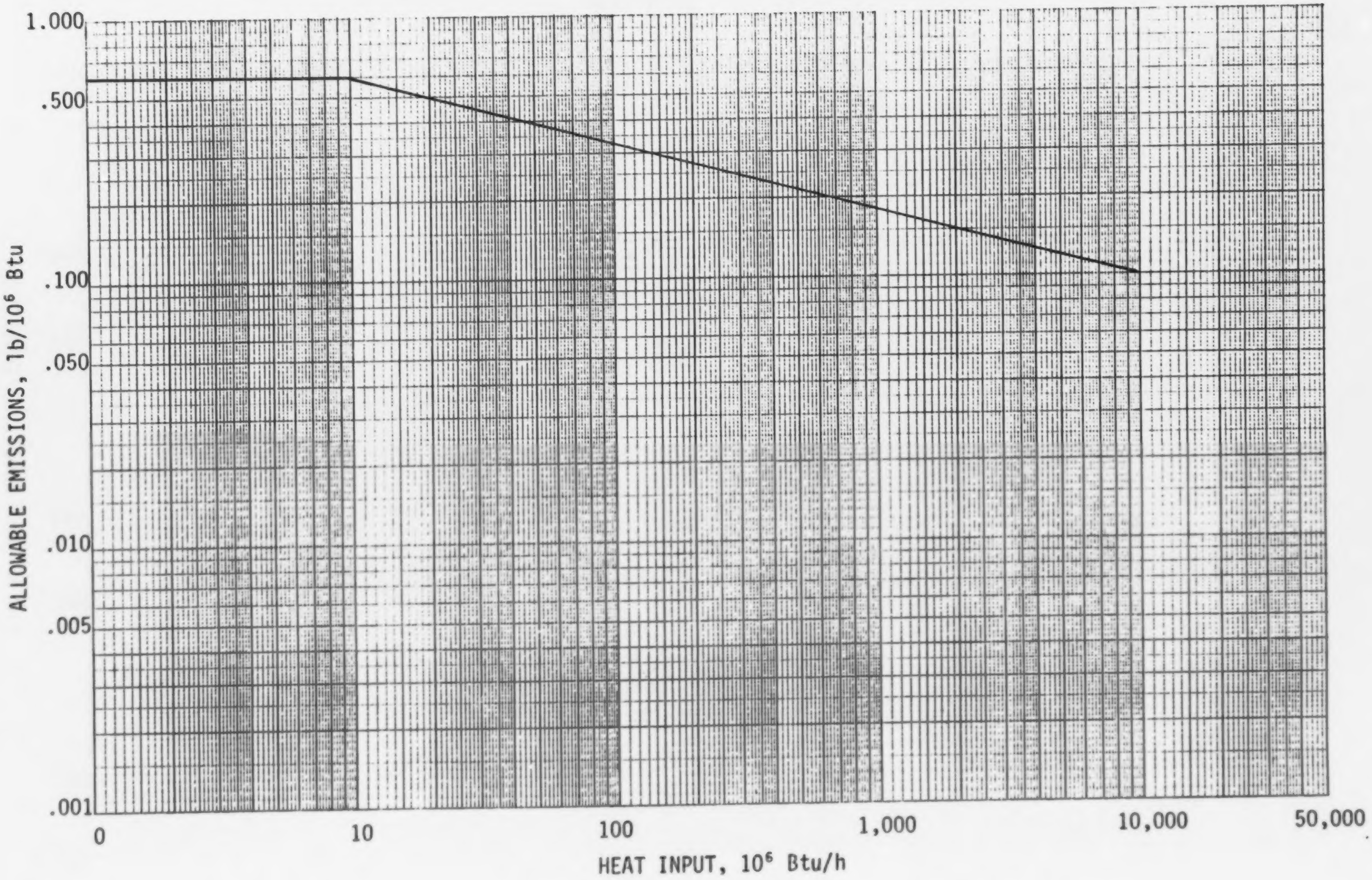
Reference Figure 1-29.



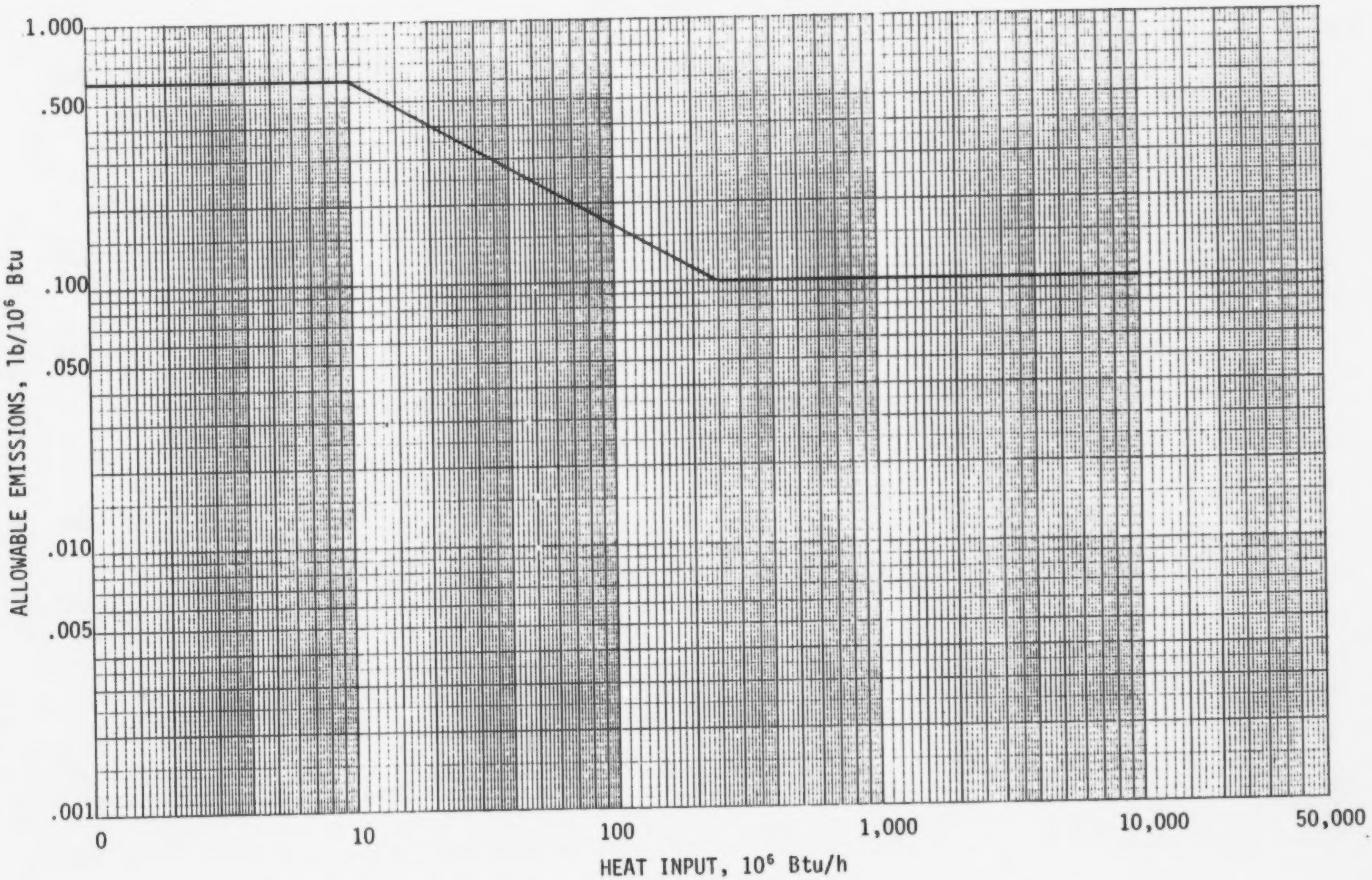
Reference Figure 1-30.



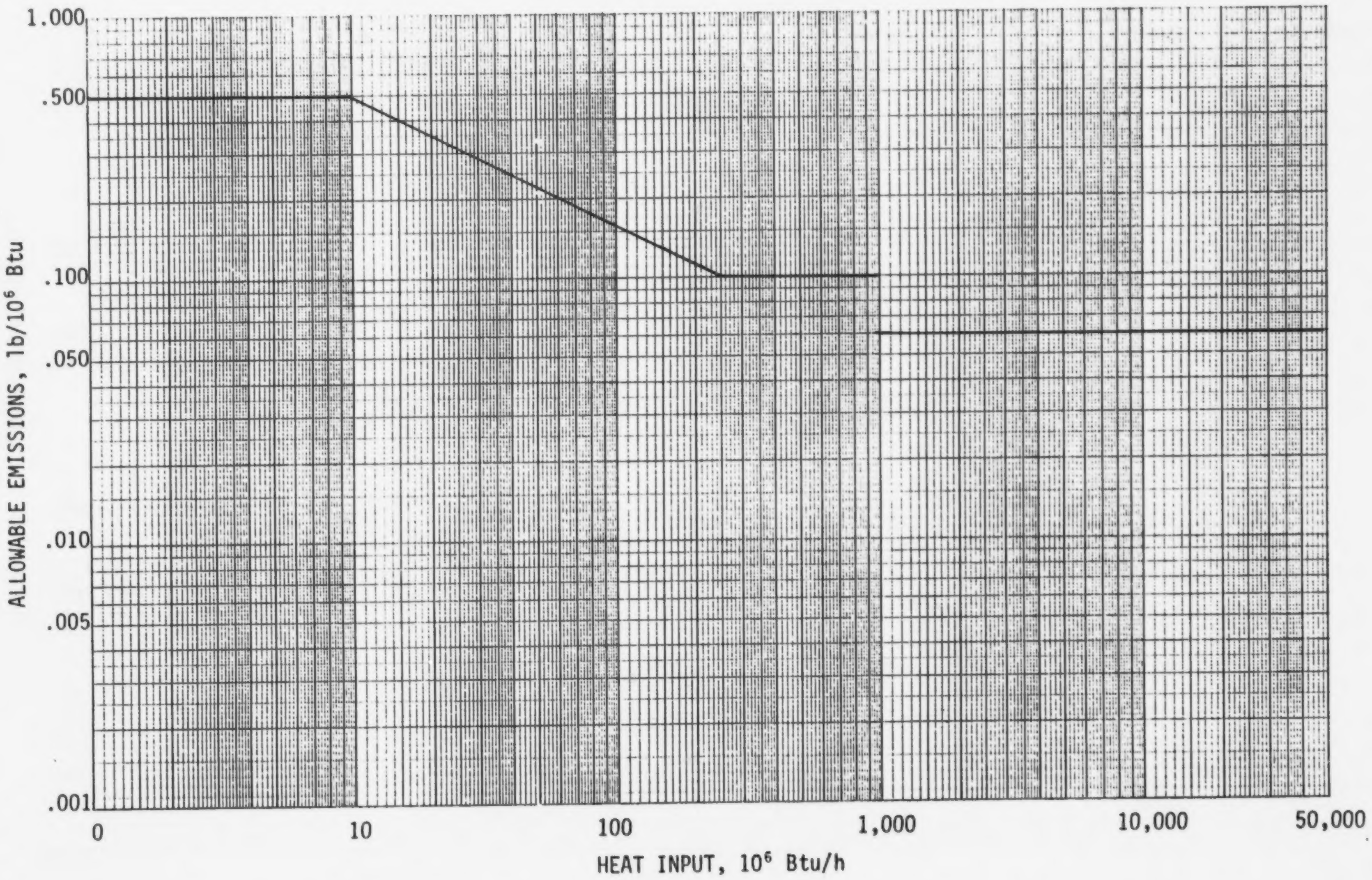
Reference Figure 1-31.



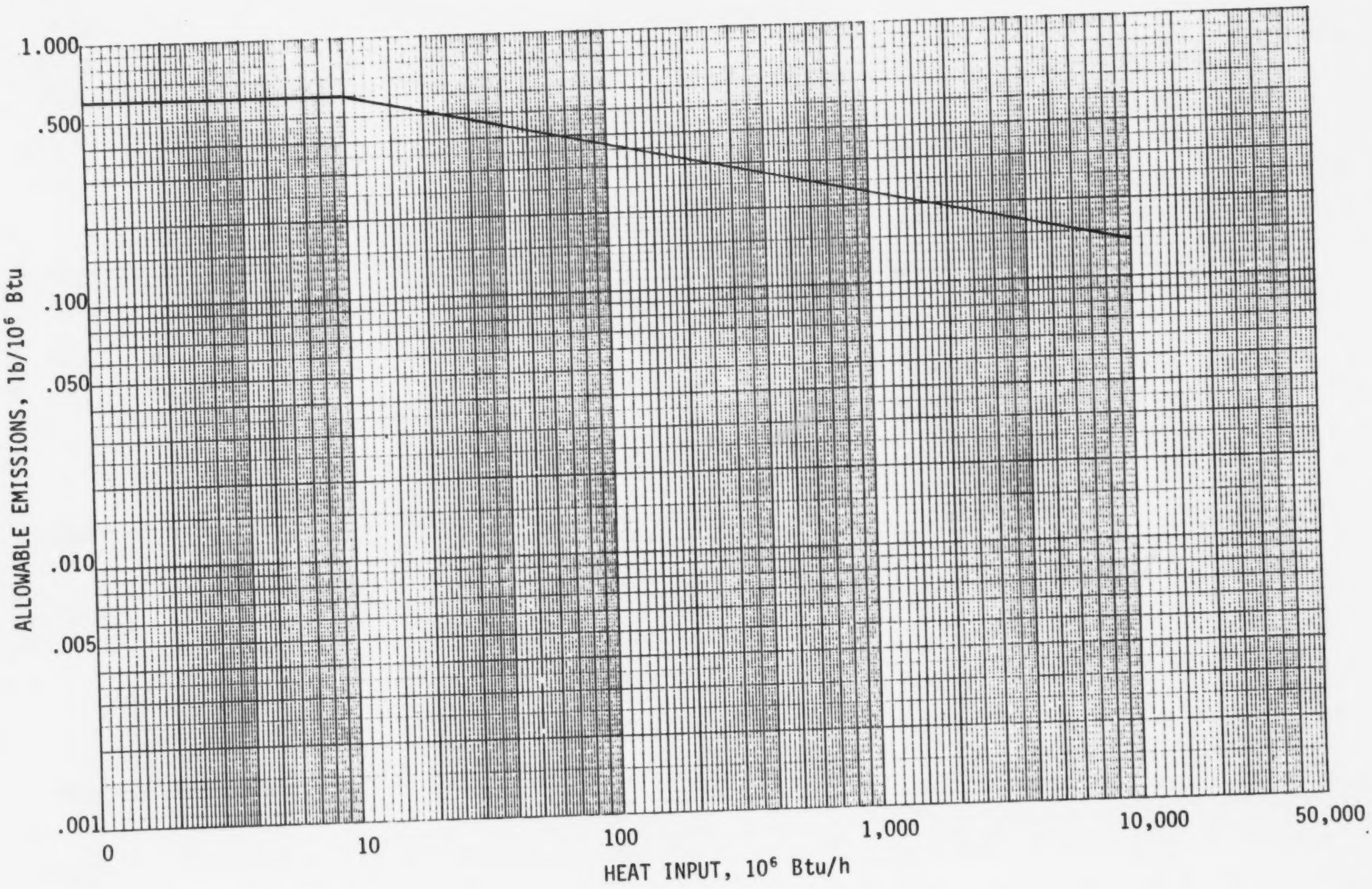
Reference Figure 1-32.



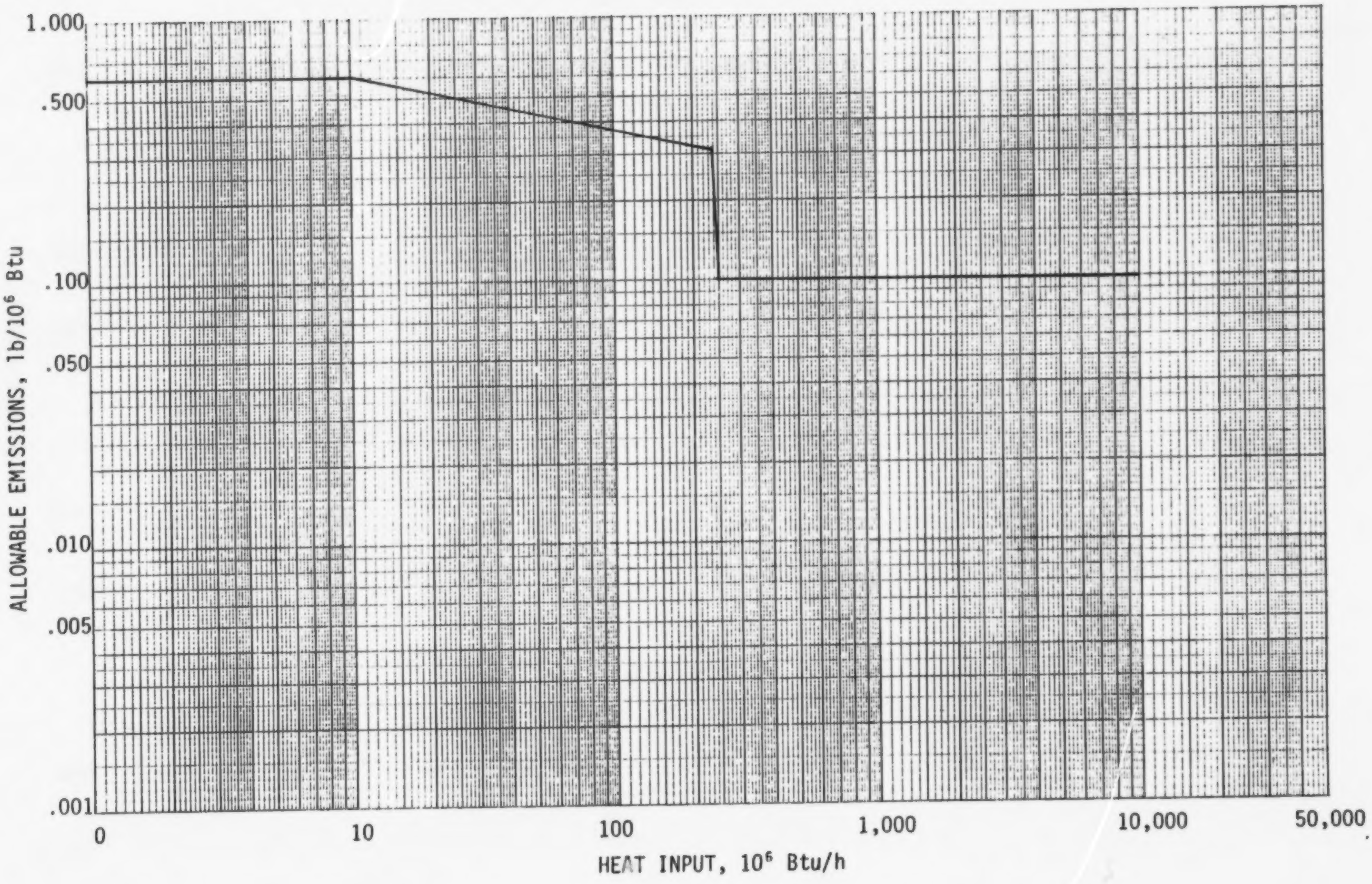
Reference Figure 1-33.



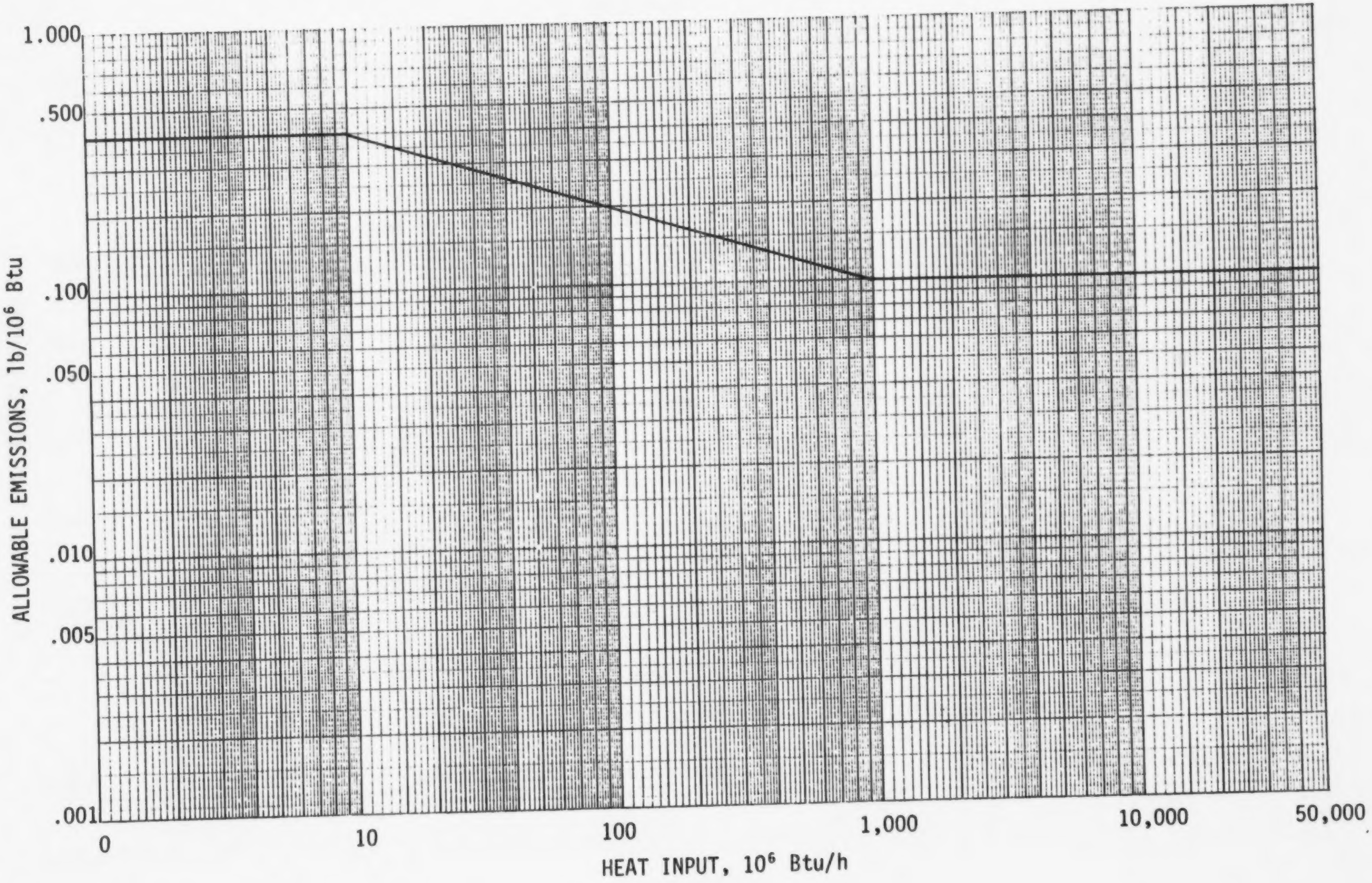
Reference Figure 1-34.



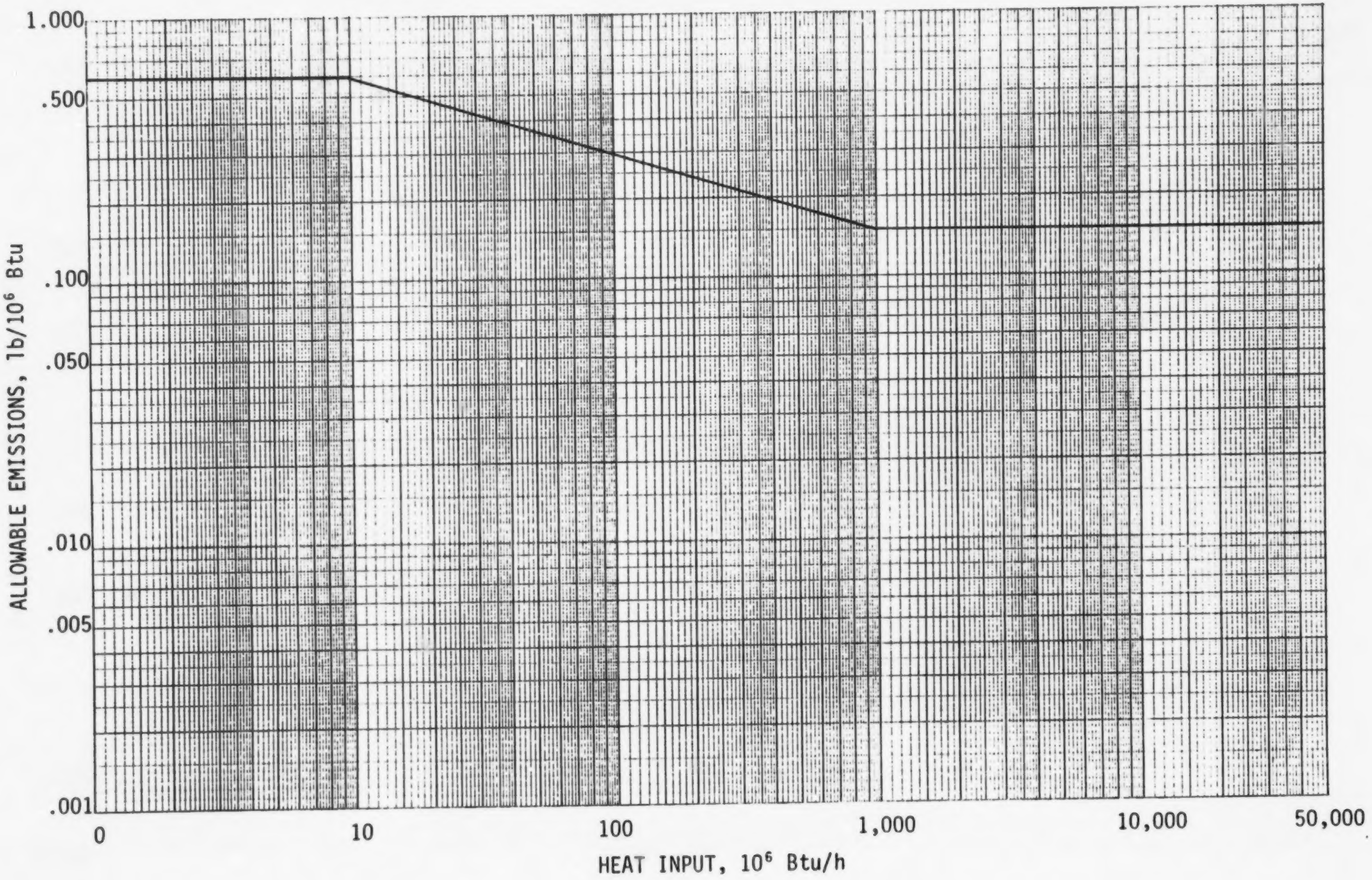
Reference Figure 1-35.



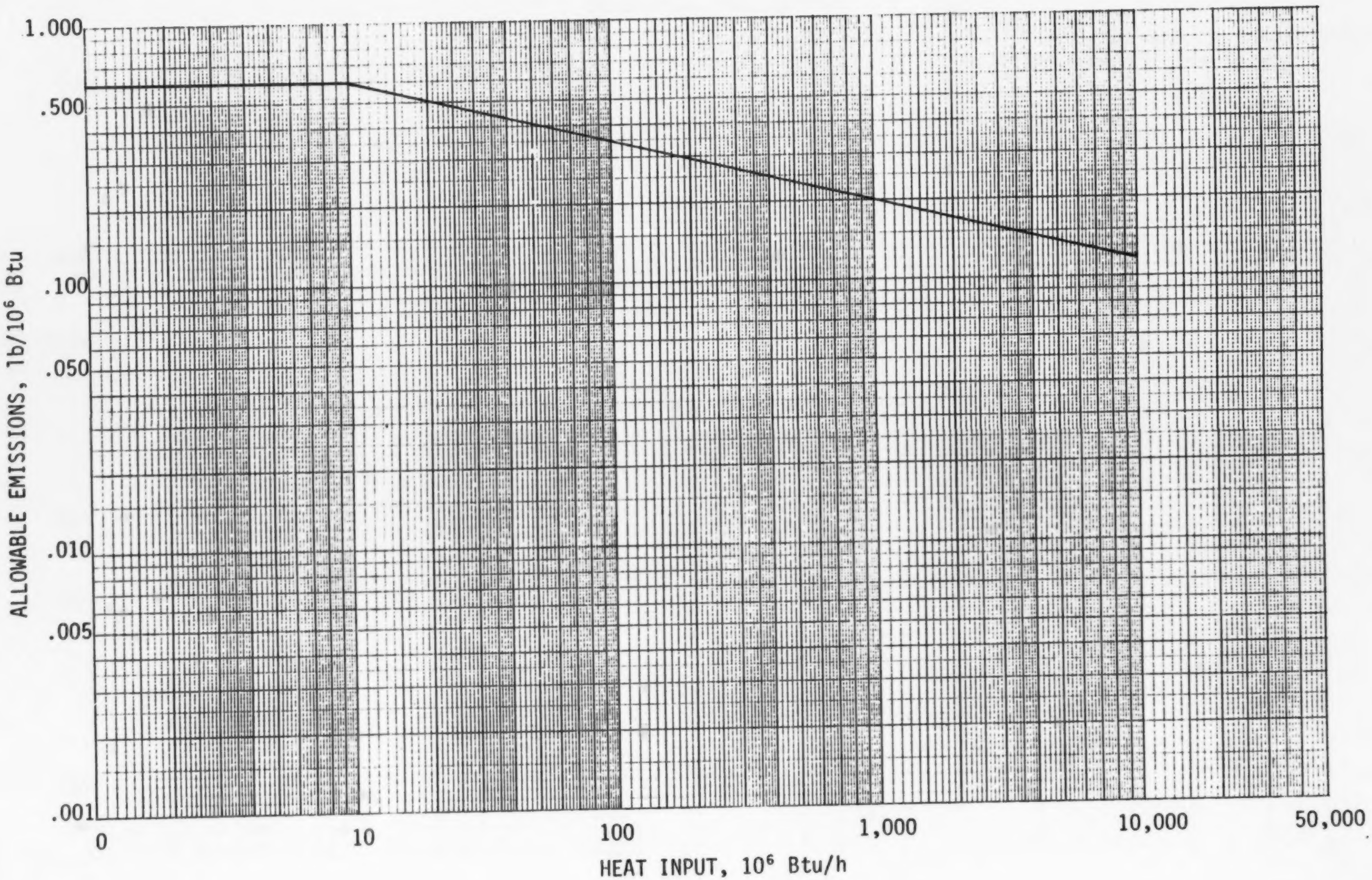
Reference Figure 1-36.



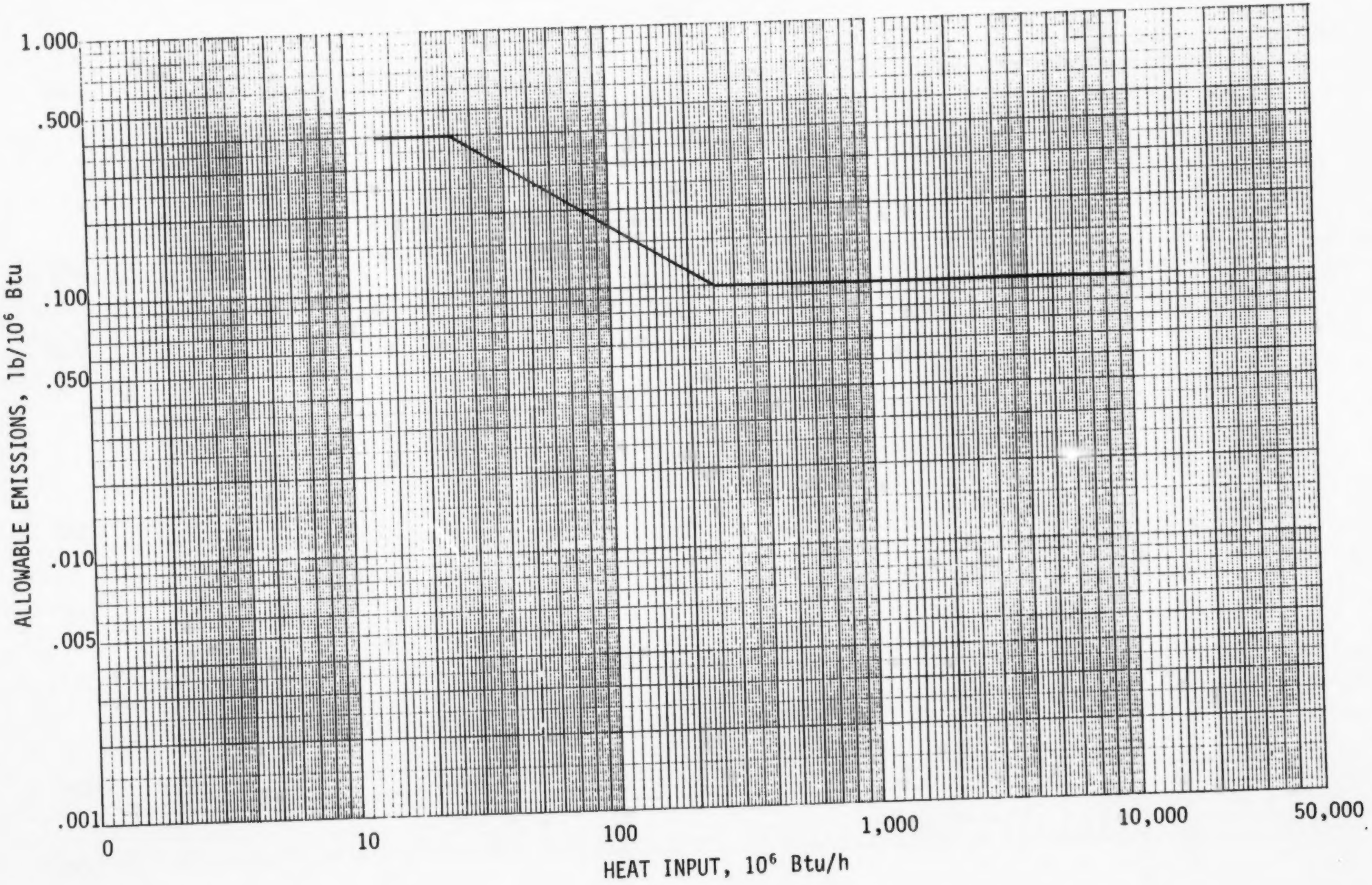
Reference Figure 1-37.



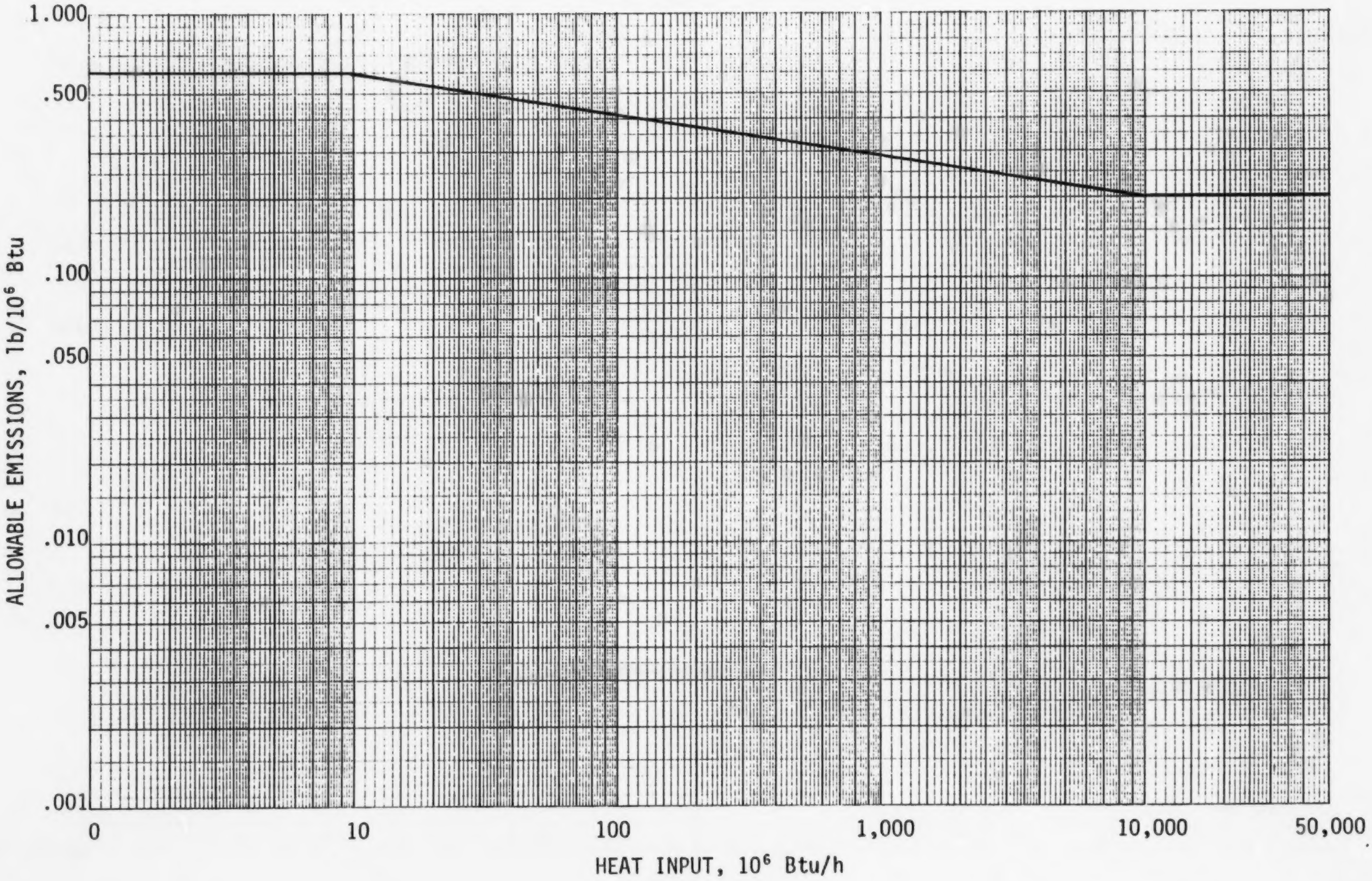
Reference Figure 1-38.



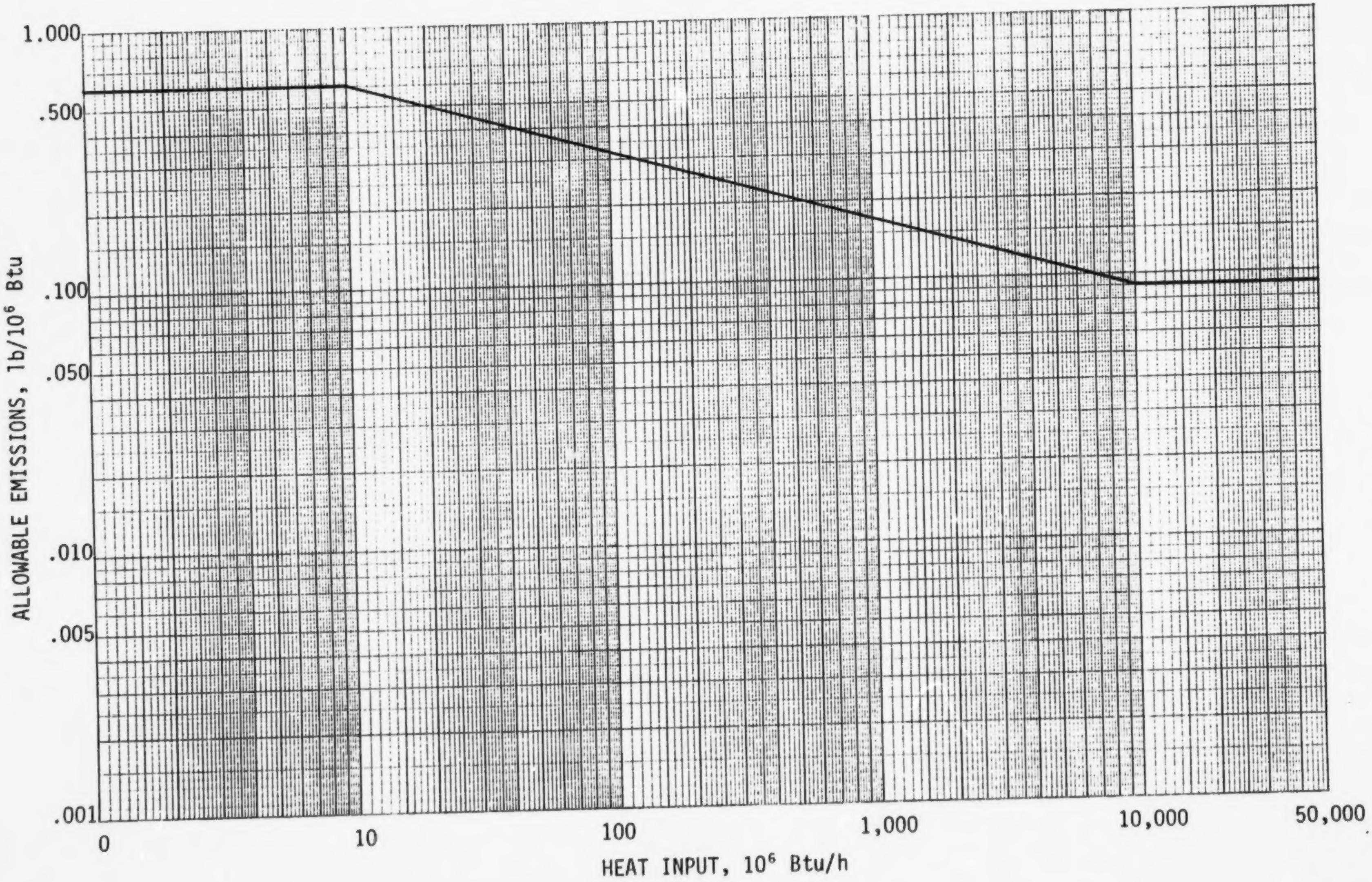
Reference Figure 1-39.



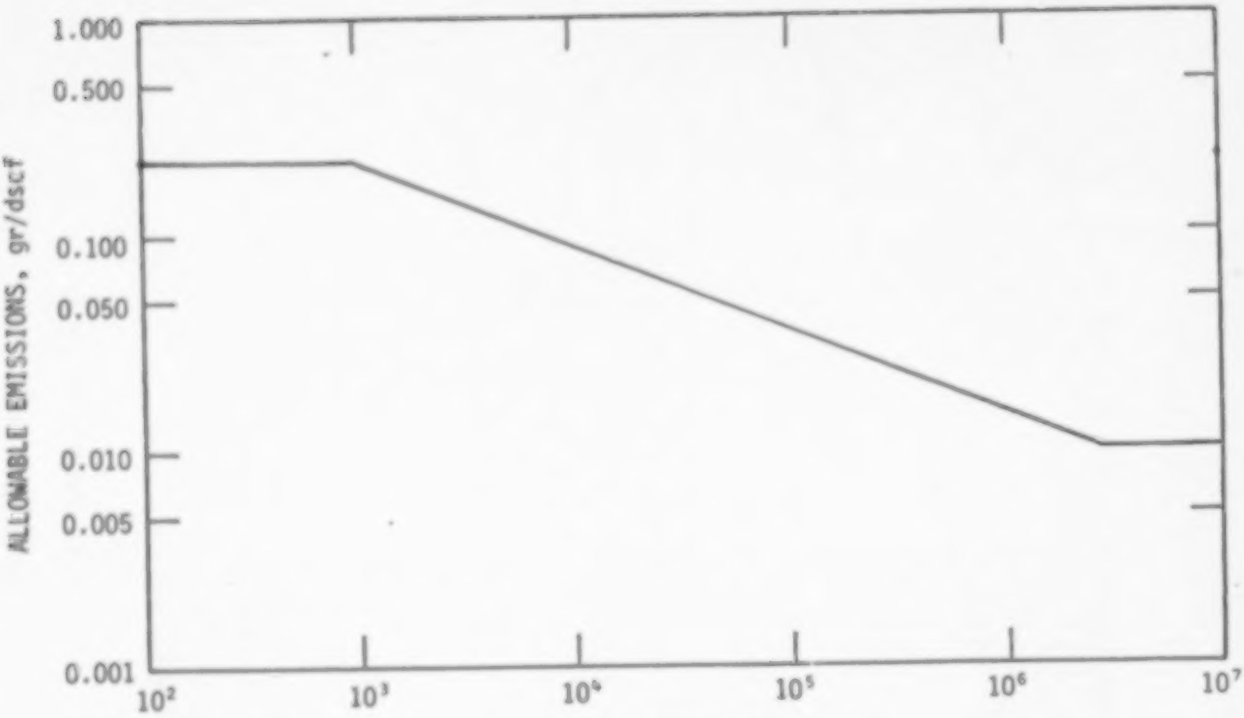
Reference Figure 1-40.



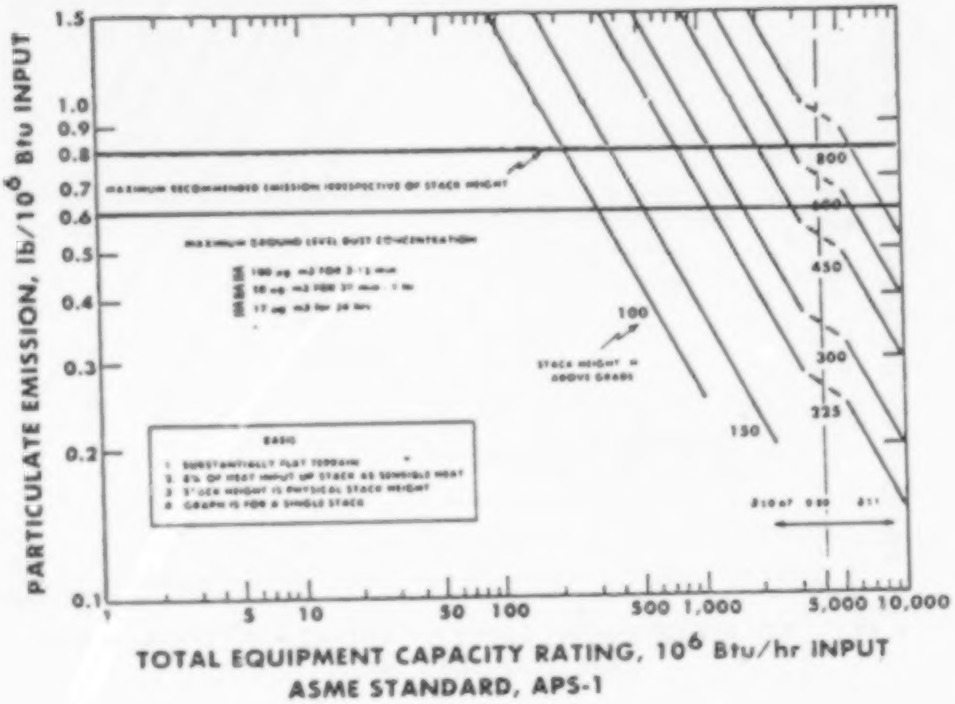
Reference Figure 1-41.



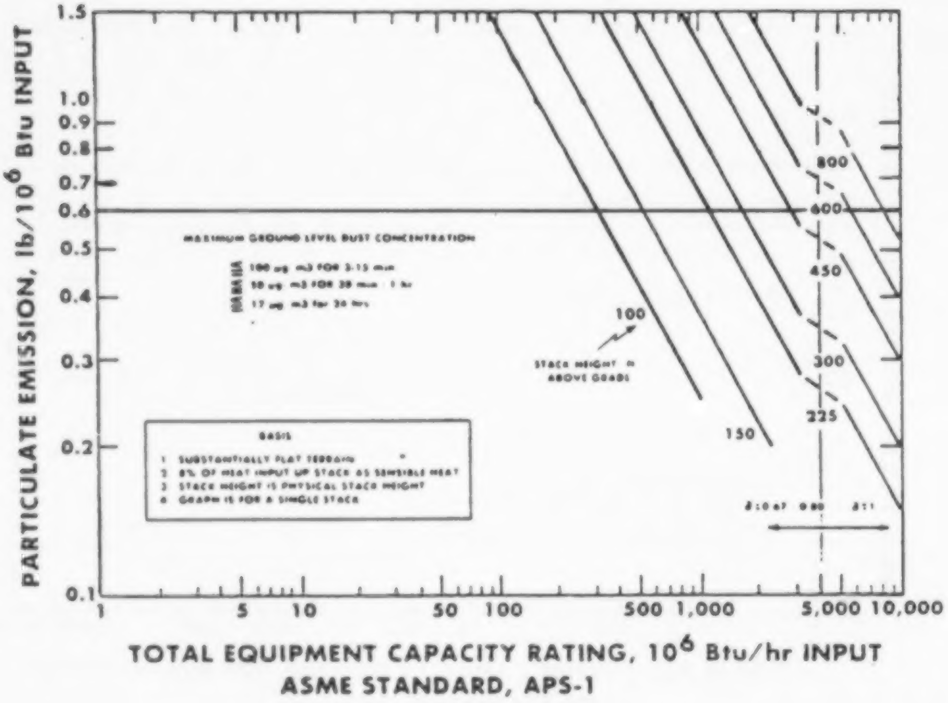
Reference Figure 1-42.



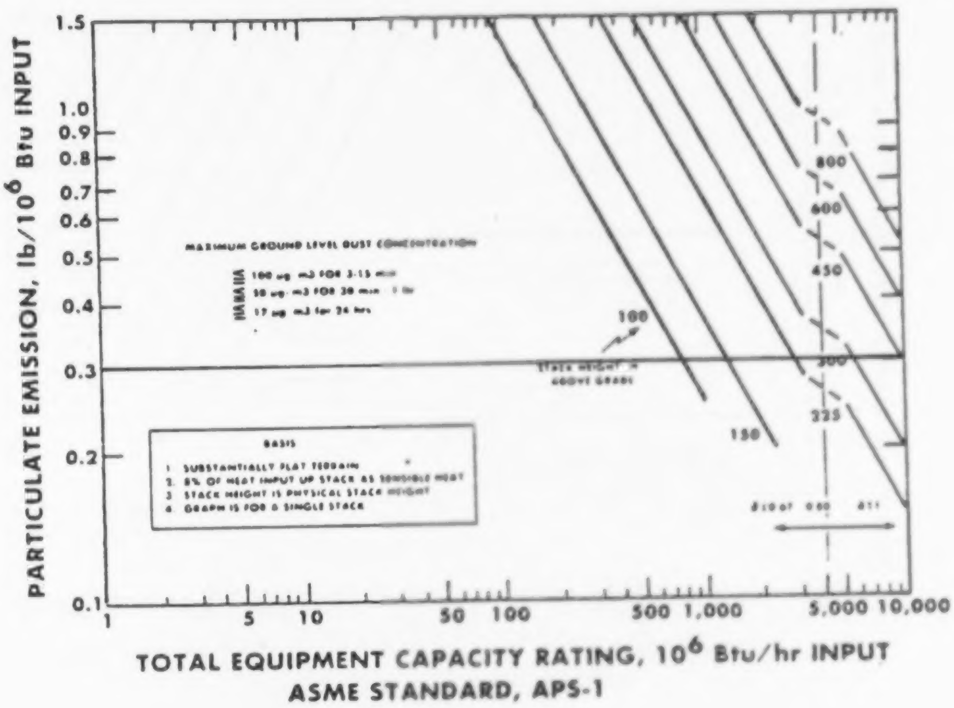
Reference Figure 2-1.



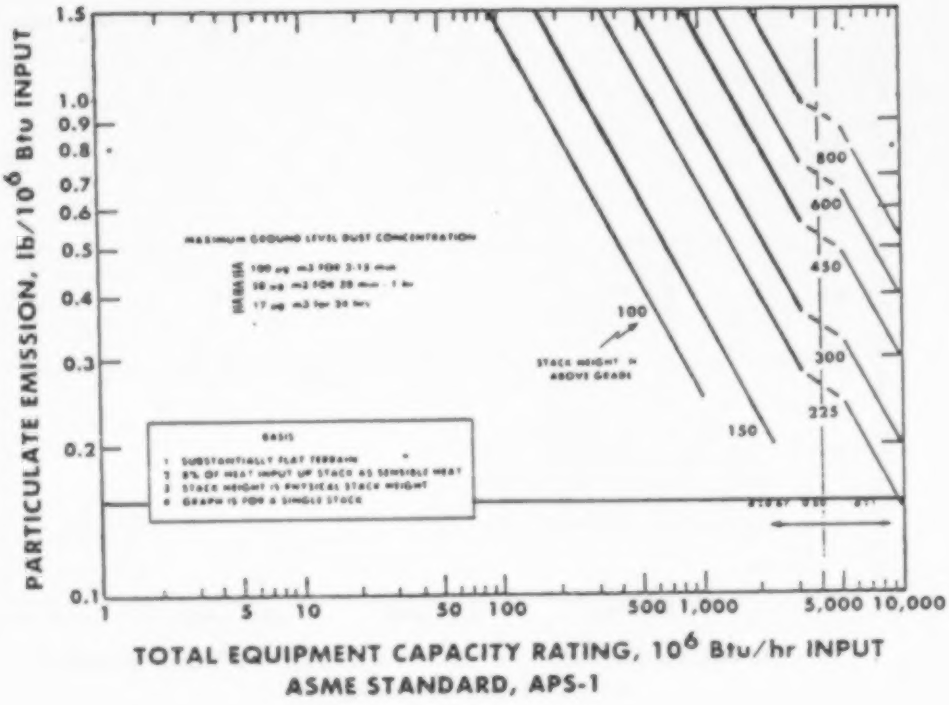
Reference Figure 3-1.



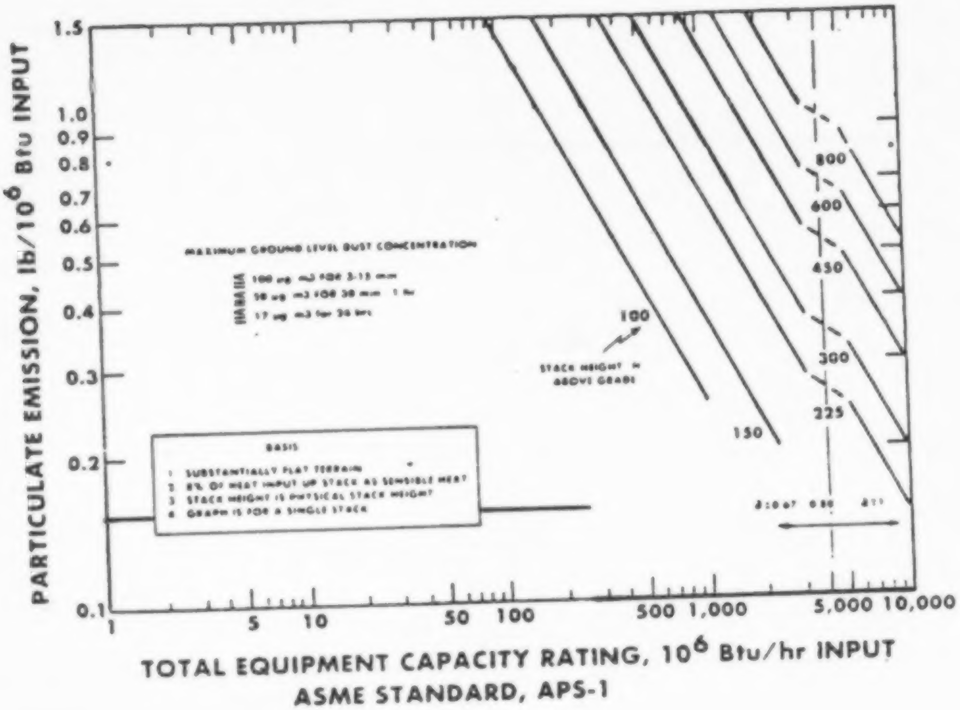
Reference Figure 3-2.



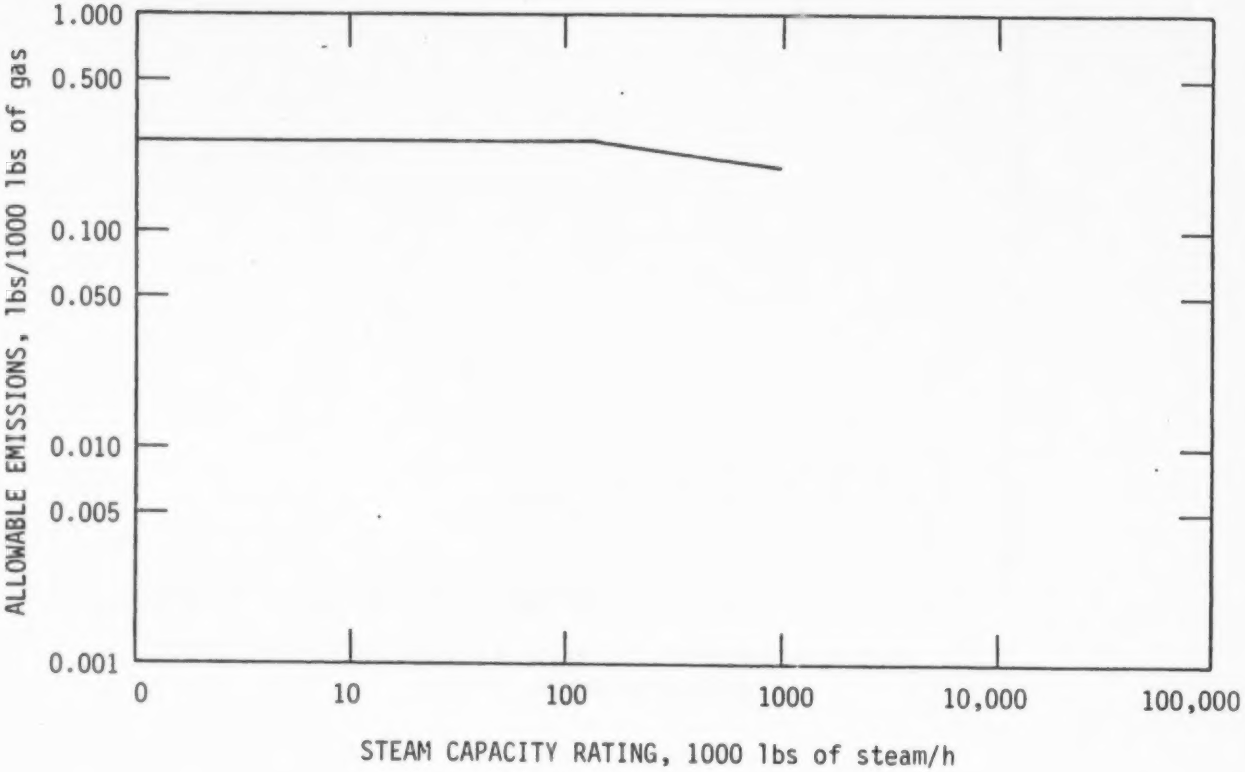
Reference Figure 3-3.



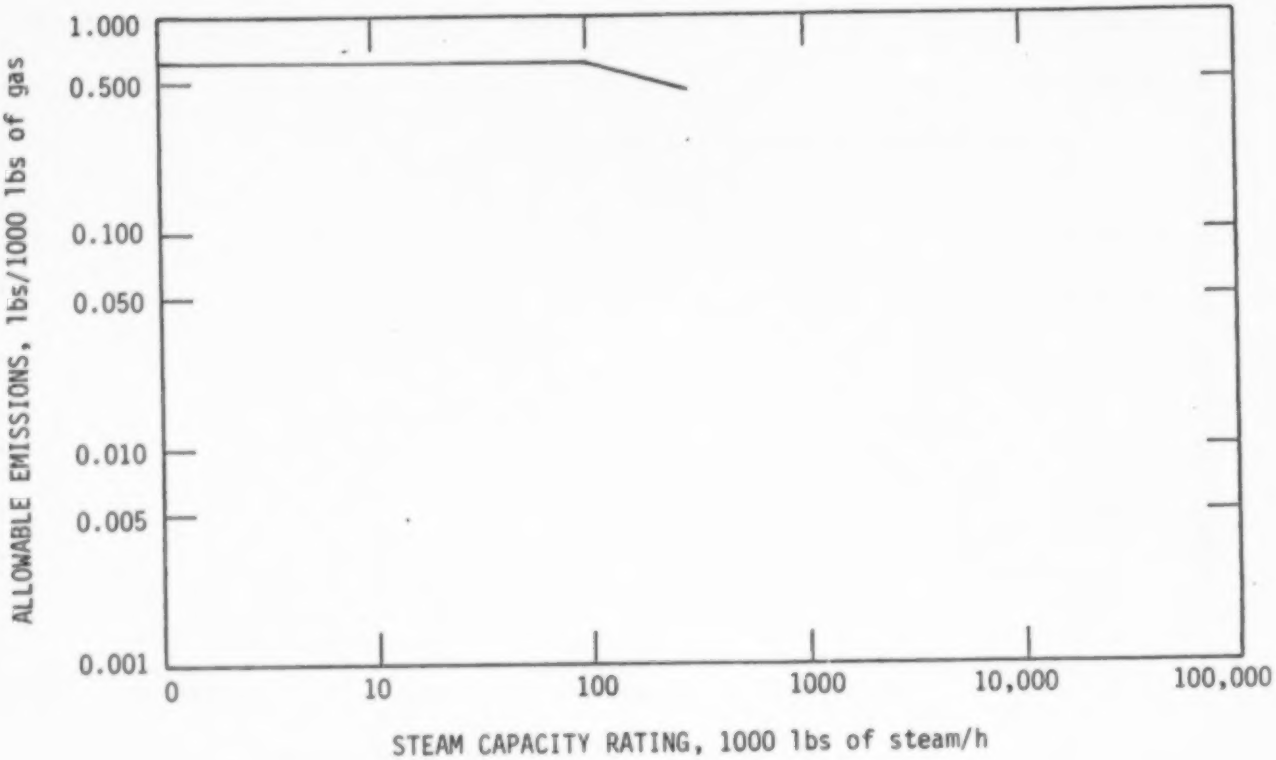
Reference Figure 3-4.



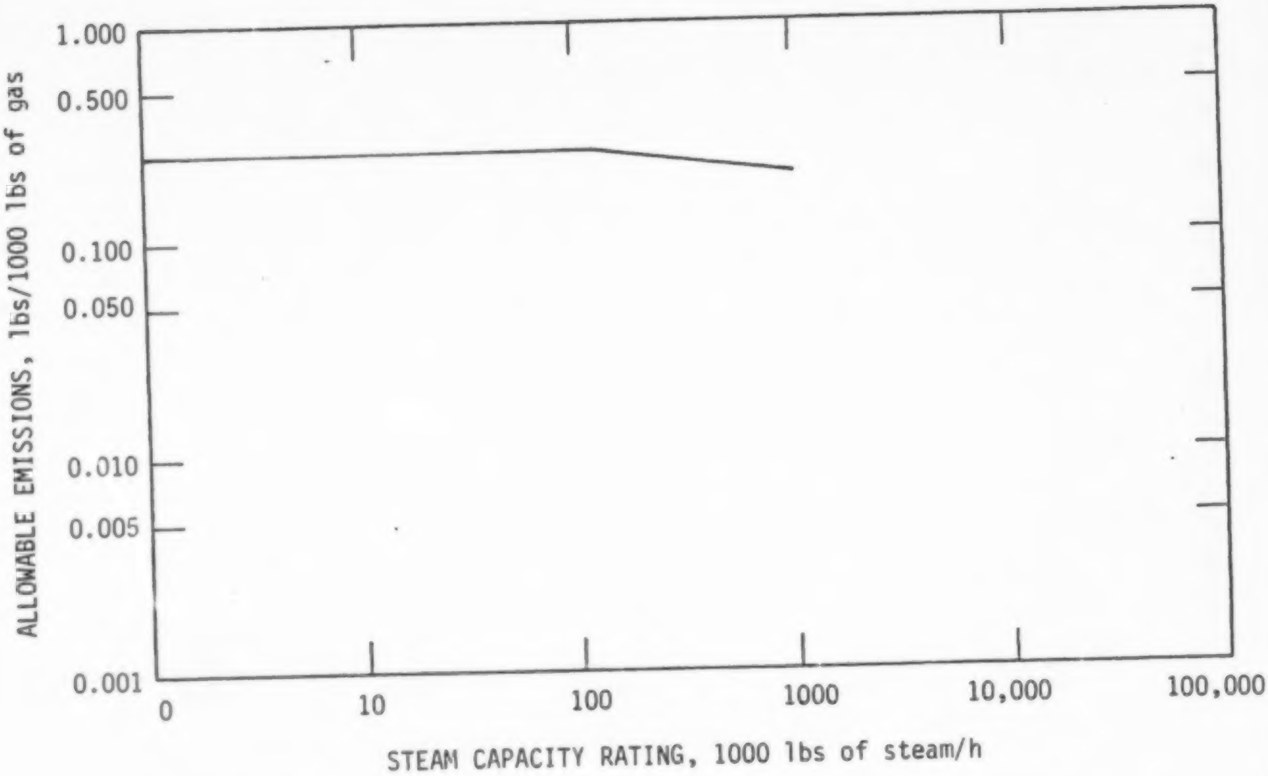
Reference Figure 3-5.



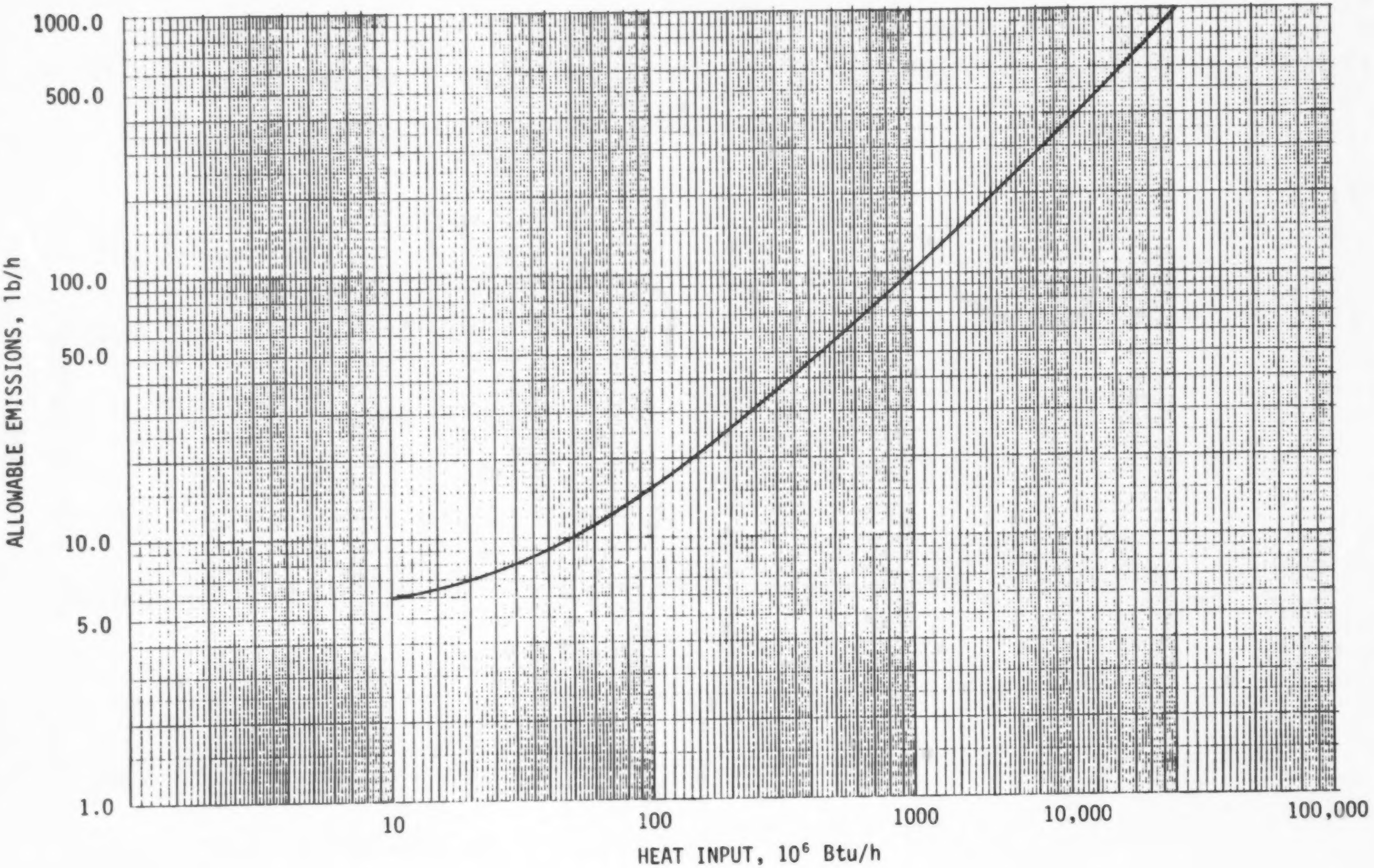
Reference Figure 4-1.



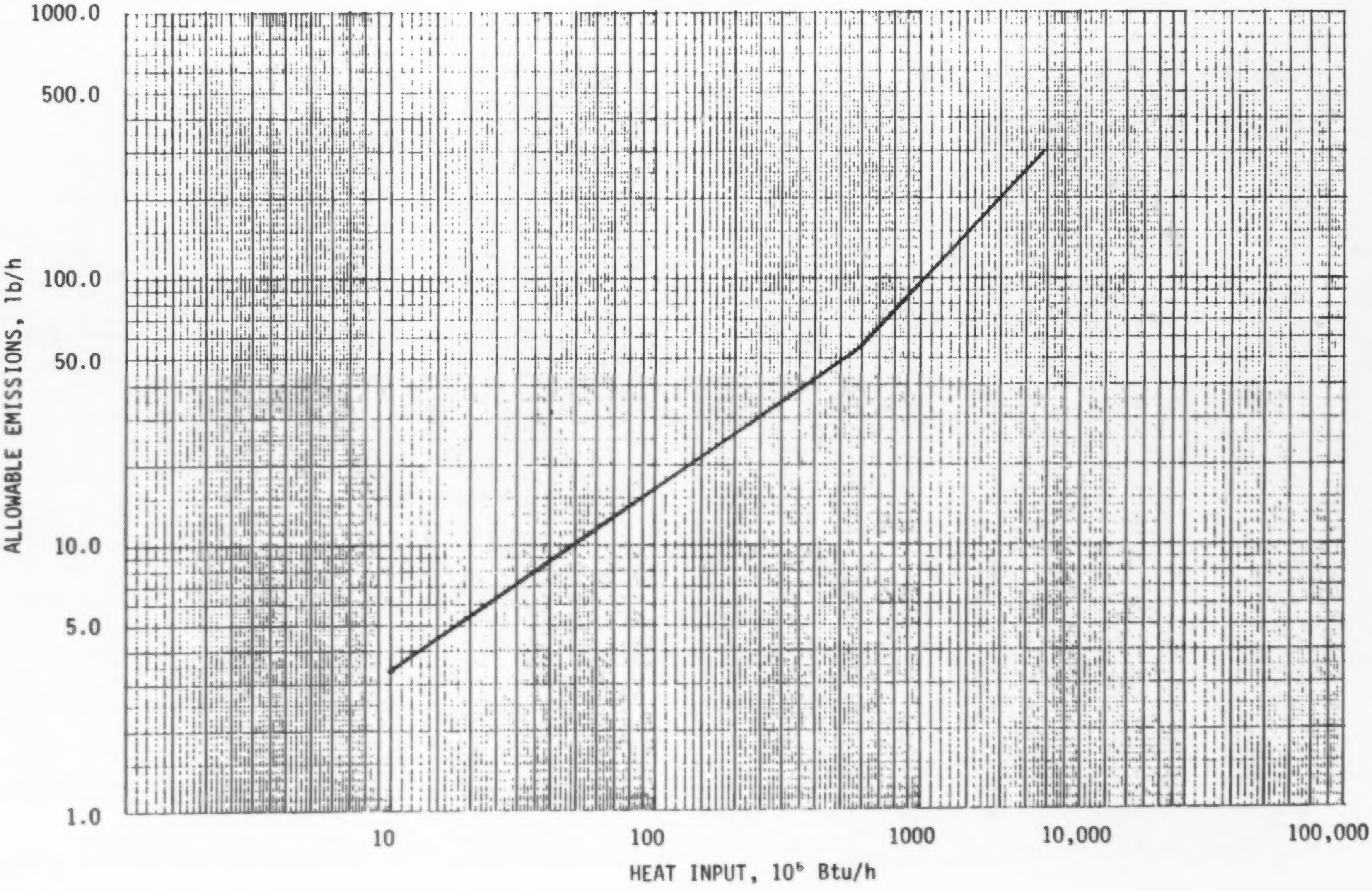
Reference Figure 4-2.



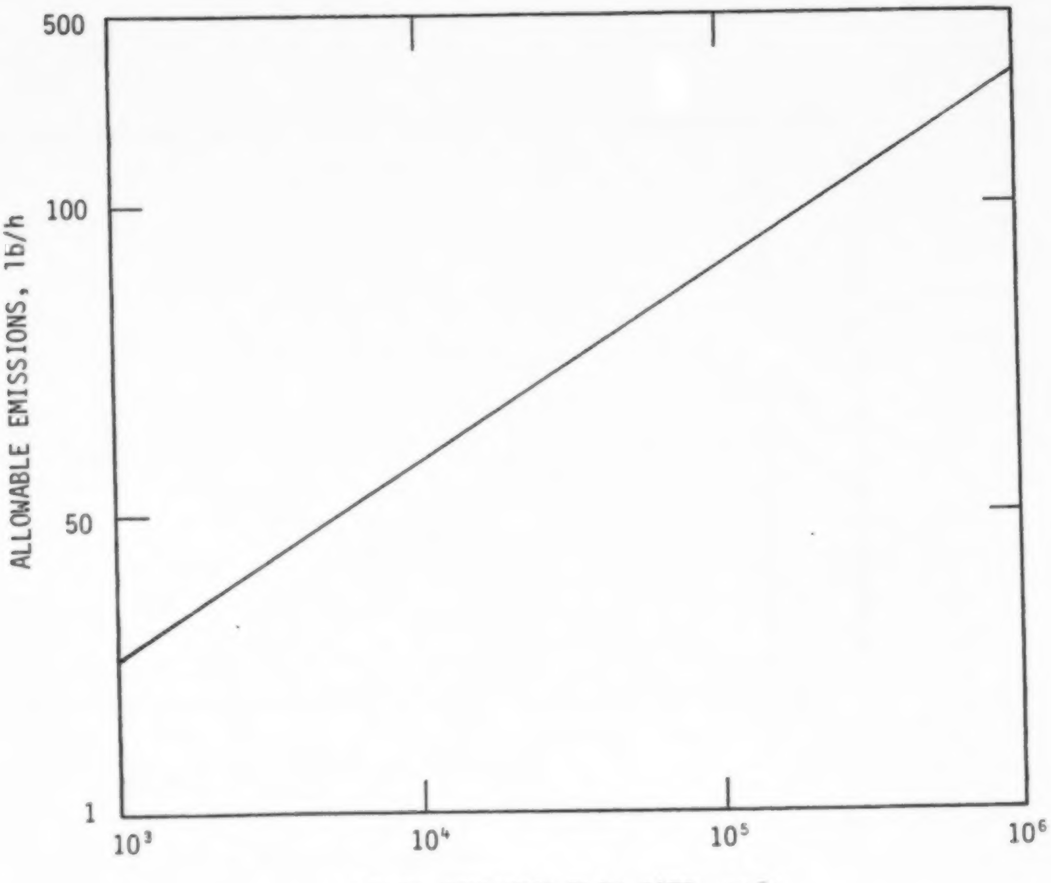
Reference Figure 4-3.



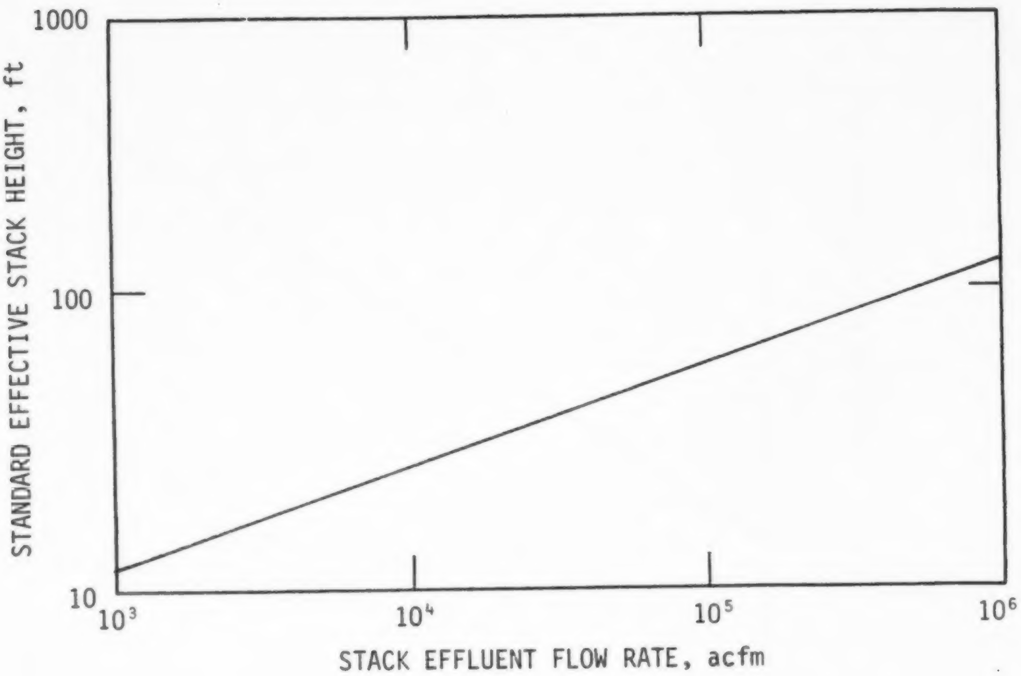
Reference Figure 5-1.



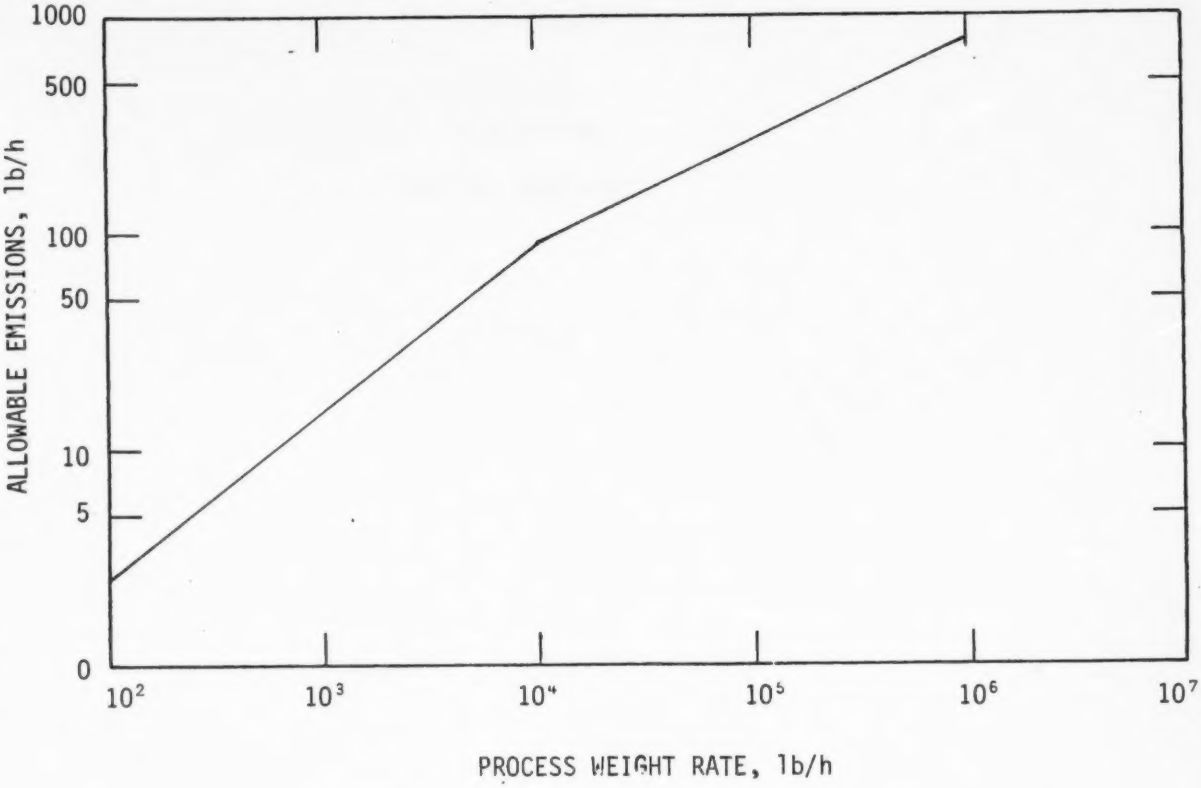
Reference Figure 5-2.



Reference Figure 6-1.



Reference Figure 6-2.



Reference Figure 7-1.

APPENDIX B

CONVERSION FACTORS

APPENDIX B

CONVERSION FACTORS

Multiply	By	To Get
Btu/hr input	10^{-7}	megawatts of steam-generated electricity (approx.)
stnd cu ft/sec	mol wt × 9.3	pounds of gas/hr
stnd cu ft/min	mol wt × 0.155	pounds of gas/hr
grams/sq m	2.85	short tons/sq mi
grams/sq m/day	86.5	short tons/sq mi/mo
grains/stnd cu ft	1.89	pounds/1000 lb gas*
grains/stnd cu ft	2300	milligrams/stnd cu m
grains/stnd cu ft	2.30	grams/stnd cu m
grains/stnd cu ft (adjusted to 50% excess air)	2.20	pounds/10^6 Btu input
grams/stnd cu m	0.435	grains/stnd cu ft
grams of gas/stnd cu m	24.2×10^3/mol wt	ppm by vol
megawatts of steam-generated electricity	10^7	Btu/hr input (approx.)
micrograms of gas/stnd cu m	0.0242/mol wt	ppm by vol
milligrams of gas/stnd cu m	24.2/mol wt	ppm by vol
milligrams/stnd cu m	4.35×10^{-4}	grains/stnd cu ft
ppm by vol	mol wt × 41.3×10^{-6}	grams of gas/stnd cu m
ppm by vol	mol wt × 0.0413	milligrams of gas/stnd cu m
ppm by vol	mol wt × 41.3	micrograms of gas/stnd cu m
ppm by vol	10^{-4}	percent by vol
percent by vol	10^4	ppm by vol
pounds of gas/hr	6.48/mol wt	stnd cu ft/min
pounds of gas/hr	0.108/mol wt	stnd cu ft/sec
pounds/1000 lb gas*	0.53	grains/stnd cu ft

Multiply	By	To Get
pounds/1000 lb gas* (adjusted to 50% excess air)	1.18	pounds/10^6 Btu input
pounds/10^6 Btu input	0.45	grains/stnd cu ft (adjusted to 50% excess air)
pounds/10^6 Btu input	0.85	pounds/1000 lb gas* (adjusted to 50% excess air)
short tons/sq mi	0.35	grams/sq m
short tons/sq mi/mo	0.0116	grams/sq m/day

*mol wt = 29

m = meter

mol wt = molecular weight

stnd = standard at 70 F and atmospheric pressure

APPENDIX C

METHOD 5--DETERMINATION OF PARTICULATE EMISSIONS FROM STATIONARY SOURCES

APPENDIX C

METHOD 5--DETERMINATION OF PARTICULATE EMISSIONS FROM STATIONARY SOURCES

1. Principle and Applicability

1.1 Principle. Particulate matter is withdrawn isokinetically from the source and collected on a glass fiber filter maintained at a temperature in the range of 120 ± 14°C (248 ± 25°F) or such other temperature as specified by an applicable subpart of the standards or approved by the Administrator, U. S. Environmental Protection Agency, for a particular application. The particulate mass, which includes any material that condenses at or above the filtration temperature, is determined gravimetrically after removal of uncombined water.

1.2 Applicability. This method is applicable for the determination of particulate emissions from stationary sources.

2. Apparatus

2.1 Sampling Train. A schematic of the sampling train used in this method is shown in Figure 5-1. Complete construction details are given in APTD-0581 (Citation 2 in Section 7); commercial models of this train are also available. For changes from APTD-0581 and for allowable modifications of the train shown in Figure 5-1, see the following subsections.

The operating and maintenance procedures for the sampling train are described in APTD-0576 (Citation 3 in Section 7). Since correct usage is important in obtaining valid results, all users should read APTD-0576 and adopt the operating and maintenance procedures outlined in it, unless otherwise specified herein. The sampling train consists of the following components:

2.1.1 Probe Nozzle. Stainless steel (316) or glass with sharp, tapered leading edge. The angle of taper shall be ≤30° and the taper shall be on the outside to preserve a constant internal diameter. The probe nozzle shall be of the button-hook or elbow design, unless otherwise specified by the Administrator. If made of stainless steel, the nozzle shall be constructed from seamless tubing; other materials of construction may be used, subject to the approval of the Administrator.

A range of nozzle sizes suitable for isokinetic sampling should be available, e.g., 0.32 to 1.27 cm (1/8 to 1/2 in.)--or larger if higher volume sampling trains are used--inside diameter (ID) nozzles in increments of 0.16 cm (1/16 in.). Each nozzle shall be calibrated according to the procedures outlined in Section 5.

2.1.2 Probe Liner. Borosilicate or quartz glass tubing with a heating system capable of maintaining a gas temperature at the exit end during sampling of 120 ± 14°C (248 ± 25°F), or such other temperature as specified by an applicable subpart of the standards or approved by the Administrator for a particular application. (The tester may opt to operate the equipment at a temperature lower than that specified.) Since the actual temperature at the outlet of the probe is not usually monitored during sampling, probes constructed according to APTD-0581 and utilizing the calibration curves of APTD-0576 (or calibrated according to the procedure outlined in APTD-0576) will be considered acceptable.

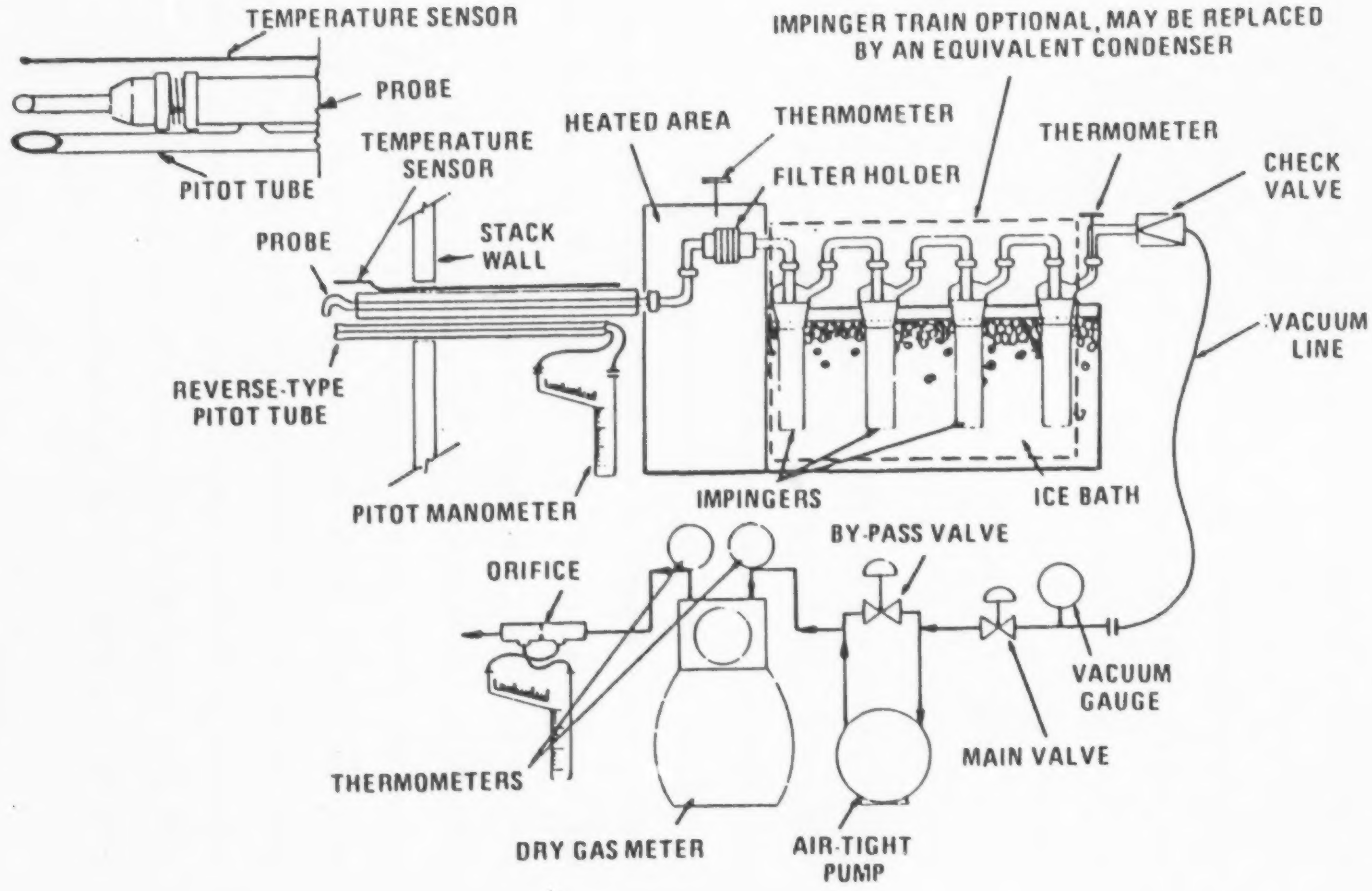

TEMPERATURE SENSOR
PROBE
PITOT TUBE
TEMPERATURE SENSOR
PROBE
STACK WALL
REVERSE-TYPE PITOT TUBE
PITOT MANOMETER
HEATED AREA
THERMOMETER
FILTER HOLDER
IMPINGER TRAIN OPTIONAL, MAY BE REPLACED BY AN EQUIVALENT CONDENSER
THERMOMETER
CHECK VALVE
VACUUM LINE
IMPINGERS
ICE BATH
BY-PASS VALVE
ORIFICE
VACUUM GAUGE
MAIN VALVE
THERMOMETERS
DRY GAS METER
AIR-TIGHT PUMP

Figure 5-1. Particulate-sampling train.

Either borosilicate or quartz glass probe liners may be used for stack temperatures up to about 480°C (900°F); quartz liners shall be used for temperatures between 480 and 900°C (900 and 1650°F). Both types of liners may be used at higher temperatures than specified for short periods of time, subject to the approval of the Administrator. The softening temperature for borosilicate is 820°C (1508°F), and for quartz it is 1500°C (2732°F).

Whenever practical, every effort should be made to use borosilicate or quartz glass probe liners. Alternatively, metal liners (e.g., 316 stainless steel, Incoloy 825,[1] or other corrosion resistant metals) made of seamless tubing may be used, subject to the approval of the Administrator.

2.1.3 Pitot Tube. Type S, as described in Section 2.1 of Method 2, or other device approved by the Administrator. The pitot tube shall be attached to the probe (as shown in Figure 5-1) to allow constant monitoring of the stack gas velocity. The impact (high pressure) opening plane of the pitot tube shall be even with or above the nozzle entry plane (see Method 2, Figure 2-6b) during sampling. The Type S pitot tube assembly shall have a known coefficient, determined as outlined in Section 4 of Method 2.

2.1.4 Differential Pressure Gauge. Inclined manometer or equivalent device (two), as described in Section 2.2 of Method 2. One manometer shall be used for velocity head (Δp) readings, and the other, for orifice differential pressure readings.

---

[1] Mention of trade names or specific products does not constitute endorsement by the Environmental Protection Agency.

2.1.5 Filter Holder. Borosilicate glass, with a glass frit filter support and a silicone rubber gasket. Other materials of construction (e.g., stainless steel, Teflon, Viton) may be used, subject to the approval of the Administrator. The holder design shall provide a positive seal against leakage from the outside or around the filter. The holder shall be attached immediately at the outlet of the probe (or cyclone, if used).

2.1.6 Filter Heating System. Any heating system capable of maintaining a temperature around the filter holder during sampling of 120 ± 14°C (248 ± 25°F), or such other temperature as specified by an applicable subpart of the standards or approved by the Administrator for a particular application. Alternatively, the tester may opt to operate the equipment at a temperature lower than that specified. A temperature gauge capable of measuring temperature to within 3°C (5.4°F) shall be installed so that the temperature around the filter holder can be regulated and monitored during sampling. Heating systems other than the one shown in APTD-0581 may be used.

2.1.7 Condenser. The following system shall be used to determine the stack gas moisture content: Four impingers connected in series with leak-free ground glass fittings or any similar leak-free non-contaminating fittings. The first, third, and fourth impingers shall be of the Greenburg-Smith design, modified by replacing the tip with a 1.3 cm (1/2 in.) ID glass tube extending to about 1.3 cm (1/2 in.) from the bottom of the flask. The second impinger shall be of the Greenburg-Smith design with the standard tip. Modifications (e.g., using flexible connections between the impingers, using materials other than glass, or using flexible vacuum lines to connect the filter holder to the condenser) may be used, subject to the approval of the Administrator. The first and second impingers shall contain known quantities of water (Section 4.1.3), the third shall be empty, and the fourth shall contain a known weight of silica gel, or equivalent desiccant. A thermometer, capable of measuring temperature to within 1°C (2°F) shall be placed at the outlet of the fourth impinger for monitoring purposes.

Alternatively, any system that cools the sample gas stream and allows measurement of the water condensed and moisture leaving the condenser, each to within 1 ml or 1 g may be used, subject to the approval of the Administrator. Acceptable means are to measure the condensed water either gravimetrically or volumetrically and to measure the moisture leaving the condenser by: (1) monitoring the temperature and pressure at the exit of the condenser and using Dalton's law of partial pressures; or (2) passing the sample gas stream through a tared silica gel (or equivalent desiccant) trap with exit gases kept below 20°C (68°F) and determining the weight gain.

If means other than silica gel are used to determine the amount of moisture leaving the condenser, it is recommended that silica gel (or equivalent) still be used between the condenser system and pump to prevent moisture condensation in the pump and metering devices and to avoid the need to make corrections for moisture in the metered volume.

Note: If a determination of the particulate matter collected in the impingers is desired in addition to moisture content, the impinger system described above shall be used, without modification. Individual States or control agencies requiring this information shall be contacted as to the sample recovery and analysis of the impinger contents.

2.1.8 Metering System. Vacuum gauge, leak-free pump, thermometers capable of measuring temperature to within 3°C (5.4°F), dry gas meter capable of measuring volume to within 2 percent, and related equipment, as shown in Figure 5-1. Other metering systems capable of maintaining sampling rates within 10 percent of isokinetic and of determining sample volumes to within 2 percent may be used, subject to the approval of the Administrator. When the metering system is used in conjunction with a pitot tube, the system shall enable checks of isokinetic rates.

Sampling trains utilizing metering systems designed for higher flow rates than that described in APTD-0581 or APTD-0576 may be used provided that the specifications of this method are met.

2.1.9 Barometer. Mercury, aneroid, or other barometer capable of measuring atmospheric pressure to within 2.5 mm Hg (0.1 in. Hg). In many cases, the barometric reading may be obtained from a nearby national weather service station, in which case the station value (which is the absolute barometric pressure) shall be requested and an adjustment for elevation differences between the weather station and sampling point shall be applied at a rate of minus 2.5 mm Hg (0.1 in. Hg) per 30 m (100 ft) elevation increase or vice versa for elevation decrease.

2.1.10 Gas Density Determination Equipment. Temperature sensor and pressure gauge, as described in Sections 2.3 and 2.4 of Method 2, and gas analyzer, if necessary, as described in Method 3. The temperature sensor shall, preferably, be permanently attached to the pitot tube or sampling probe in a fixed configuration, such that the tip of the sensor extends beyond the leading edge of the probe sheath and does not touch any metal. Alternatively, the sensor may be attched just prior to use in the field. Note, however, that if the temperature sensor is attached in the field, the sensor must be placed in an interference-free arrangement with respect to the Type S pitot tube openings (see Method 2, Figure 2-7). As a second alternative, if a difference of not more than 1 percent in the average velocity measurement is to be introduced, the temperature gauge need not be attached to the probe or pitot tube. (This alternative is subject to the approval of the Administrator.)

2.2 Sample Recovery. The following items are needed:

2.2.1 Probe-Liner and Probe-Nozzle Brushes. Nylon bristle brushes with stainless steel wire handles. The probe brush shall have extensions (at least as long as the probe) of stainless steel, Nylon, Teflon, or similarly inert material. The brushes shall be properly sized and shaped to brush out the probe liner and nozzle.

2.2.2 Wash Bottles--Two. Glass wash bottles are recommended; polyethylene wash bottles may be used at the option of the tester. It is recommended that acetone not be stored in polyethylene bottles for longer than a month.

2.2.3 Glass Sample Storage Containers. Chemically resistant, borosilicate glass bottles, for acetone washes, 500 ml or 1000 ml. Screw cap liners shall either be rubber-backed Teflon or shall be constructed so as to be leak-free and resistant to chemical attack by acetone. (Narrow mouth glass bottles have been found to be less prone to leakage.) Alternatively, polyethylene bottles may be used.

2.2.4 Petri Dishes. For filter samples, glass or polyethylene, unless otherwise specified by the Administrator.

2.2.5 Graduated Cylinder and/or Balance. To measure condensed water to within 1 ml or 1 g. Graduated cylinders shall have subdivisions no greater than 2 ml. Most laboratory balances are capable of weighing to the nearest 0.5 g or less. Any of these balances is suitable for use here and in Section 2.3.4.

2.2.6 Plastic Storage Containers. Air-tight containers to store silica gel.

2.2.7 Funnel and Rubber Policeman. To aid in transfer of silica gel to container; not necessary if silica gel is weighed in the field.

2.2.8 Funnel. Glass or polyethylene, to aid in sample recovery.

2.3 Analysis. For analysis, the following equipment is needed:

2.3.1 Glass Weighing Dishes.

2.3.2 Desiccator.

2.3.3 Analytical Balance. To measure to within 0.1 mg.

2.3.4 Balance. To measure to within 0.5 g.

2.3.5 Beakers. 250 ml.

2.3.6 Hygrometer. To measure the relative humidity of the laboratory environment.

2.3.7 Temperature Gauge. To measure the temperature of the laboratory environment.

3. Reagents

3.1 Sampling. The reagents used in sampling are as follows:

3.1.1 Filters. Glass fiber filters, without organic binder, exhibiting at least 99.95 percent efficiency ($\leq$0.05 percent penetration) on 0.3-micron dioctyl phthalate smoke particles. The filter efficiency test shall be conducted in accordance with ASTM standard method D 2986-71. Test data from the supplier's quality control program are sufficient for this purpose.

3.1.2 Silica Gel. Indicating type, 6 to 16 mesh. If previously used, dry at 175°C (350°F) for 2 hours. New silica gel may be used as received. Alternatively, other types of desiccants (equivalent or better) may be used, subject to the approval of the Administrator.

3.1.3 Water. When analysis of the material caught in the impingers is required, distilled water shall be used. Run blanks prior to field use to eliminate a high blank on test samples.

3.1.4 Crushed Ice.

3.1.5 Stopcock Grease. Acetone-insoluble, heat-stable silicone grease. This is not necessary if screw-on connectors with Teflon sleeves, or similar, are used. Alternatively, other types of stopcock grease may be used, subject to the approval of the Administrator.

3.2 Sample Recovery. Acetone--reagent grade, $\leq$0.001 percent residue, in glass bottles--is required. Acetone from metal containers generally has a high residue blank and should not be used. Sometimes, suppliers transfer acetone to glass bottles from metal containers; thus, acetone blanks shall be run prior to field use and only acetone with low blank values ($\leq$0.001 percent) shall be used. In no case shall a blank value of greater than 0.001 percent of the weight of acetone used be subtracted from the sample weight.

3.3 Analysis. Two reagents are required for the analysis:

3.3.1 Acetone. Same as 3.2.

3.3.2 Desiccant. Anhydrous calcium sulfate, indicating type. Alternatively, other types of desiccants may be used, subject to the approval of the Administrator.

4. Procedure

4.1 Sampling. The complexity of this method is such that, in order to obtain reliable results, testers should be trained and experienced with the test procedures.

4.1.1 Pretest Preparation. All the components shall be maintained and calibrated according to the procedure described in APTD-0576, unless otherwise specified herein.

Weigh several 200 to 300 g portions of silica gel in air-tight containers to the nearest 0.5 g. Record the total weight of the silica gel plus container, on each container. As an alternative, the silica gel need not be preweighed, but may be weighed directly in its impinger or sampling holder just prior to train assembly.

Check filters visually against light for irregularities and flaws or pinhole leaks. Label filters of the proper diameter on the back side near the edge using numbering machine ink. As an alternative, label the shipping containers (glass or plastic petri dishes) and keep the filters in these containers at all times except during sampling and weighing....

Desiccate the filters at 20 ± 5.6°C (68 ± 10°F) and ambient pressure for at least 24 hours and weigh at intervals of at least 6 hours to a constant weight, i.e., $\leq$0.5 mg change from previous weighing; record results to the nearest 0.1 mg. During each weighing the filter must not be exposed to the laboratory atmosphere for a period greater than 2 minutes and a relative humidity above 50 percent. Alternatively (unless otherwise specified by the Administrator), the filters may be oven dried at 105°C (220°F) for 2 to 3 hours, desiccated for 2 hours, and weighed. Procedures other than those described, which account for relative humidity effects, may be used, subject to the approval of the Administrator.

4.1.2 Preliminary Determinations. Select the sampling site and the minimum number of sampling points according to Method 1 or as specified by the Administrator. Determine the stack pressure, temperature, and the range of velocity heads using Method 2; it is recommended that a leak-check of the pitot lines (see Method 2, Section 3.1) be performed. Determine the moisture content using Approximation Method 4 or its alternatives for the purpose of making isokinetic sampling rate settings. Determine the stack gas dry molecular weight, as described in Method 2, Section 3.6; if integrated Method 3 sampling is used for molecular weight determination, the integrated bag sample shall be taken simultaneously with, and for the same total length of time as, the particulate sample run.

Select a nozzle size based on the range of velocity heads, such that it is not necessary to change the nozzle size in order to maintain isokinetic sampling rates. During the run, do not change the nozzle size. Ensure that the proper differential pressure gauge is chosen for the range of velocity heads encountered (see Section 2.2 of Method 2).

Select a suitable probe liner and probe length such that all traverse points can be sampled. For large stacks, consider sampling from opposite sides of the stack to reduce the length of probes.

Select a total sampling time greater than or equal to the minimum total sampling time specified in the test procedures for the specific industry such that (1) the sampling time per point is not less than 2 min. (or some greater time interval as specified by the Administrator), and (2) the sample volume taken (corrected to standard conditions) will exceed the required minimum total gas sample volume. The latter is based on an approximate average sampling rate.

The sampling time at each point shall be the same. It is recommended that the number of minutes sampled at each point be an integer or an integer plus onehalf minute, in order to avoid timekeeping errors.

In some circumstances, e.g., batch cycles, it may be necessary to sample for shorter times at the traverse points and to obtain smaller gas sample volumes. In these cases, the Administrator's approval must first be obtained.

4.1.3 Preparation of Collection Train. During preparation and assembly of the sampling train, keep all openings where contamination can occur covered until just prior to assembly or until sampling is about to begin.

Place 100 ml of water in each of the first two impingers, leave the third impinger empty, and transfer approximately 200 to 300 g of preweighed silica gel from its container to the fourth impinger. More silica gel may be used, but care should be taken to ensure that it is not entrained and carried out from the impinger during sampling. Place the container in a clean place for later use in the sample recovery. Alternatively, the weight of the silica gel plus impinger may be determined to the nearest 0.5 g and recorded.

Using a tweezer or clean disposable surgical gloves, place a labeled (identified) and weighed filter in the filter holder. Be sure that the filter is properly centered and the gasket properly placed so as to prevent the sample gas stream from circumventing the filter. Check the filter for tears after assembly is completed.

When glass liners are used, install the selected nozzle using a Viton A O-ring when stack temperatures are less than 260°C (500°F) and an asbestos string gasket when temperatures are higher. See APTD-0576 for details. Other connecting systems using either 316 stainless steel or Teflon ferrules may be used. When metal liners are used, install the nozzle as above or by a leak-free direct mechanical connection. Mark the probe with heat resistant tape or by some other method to denote the proper distance into the stack or duct for each sampling point.

Set up the train as in Figure 5-1, using (if necessary) a very light coat of silicone grease on all ground glass joints, greasing only the outer portion (see APTD-0576) to avoid possibility of contamination by the silicone grease. Subject to the approval of the Administrator, a glass cyclone may be used between the probe and filter holder when the total particulate catch is expected to exceed 100 mg or when water droplets are present in the stack gas.

Place crushed ice around the impingers.

4.1.4 Leak-Check Procedures.

4.1.4.1 Pretest Leak-Check. A pretest leak-check is recommended, but not required. If the tester opts to conduct the pretest leak-check, the following procedure shall be used.

After the sampling train has been assembled, turn on and set the filter and probe heating systems at the desired operating temperatures. Allow time for the temperatures to stabilize. If a Viton A O-ring or other leak-free connection is used in assembling the probe nozzle to the probe liner, leak-check the train at the sampling site by plugging the nozzle and pulling a 380 mm Hg (15 in. Hg) vacuum.

Note: A lower vacuum may be used, provided that it is not exceeded during the test.

If an asbestos string is used, do not connect the probe to the train during the leak-check. Instead, leak-check the train by first plugging the inlet to the filter holder (cyclone, if applicable) and pulling a 380 mm Hg (15 in. Hg) vacuum (see Note immediately above). Then connect the probe to the train and leak-check at about 25 mm Hg (1 in. Hg) vacuum; alternatively, the probe may be leak-checked with the rest of the sampling train, in one step, at 380 mm Hg (15 in. Hg) vacuum. Leakage rates in excess of 4 percent of the average sampling rate or 0.00057 m^3/min (0.02 cfm), whichever is less, are unacceptable.

The following leak-check instructions for the sampling train described in APTD-0576 and APTD-0581 may be helpful. Start the pump with bypass valve fully open and coarse adjust valve completely closed. Partially open the coarse adjust valve and slowly close the bypass valve until the desired vacuum is reached. Do not reverse direction of bypass valve; this will cause water to back up into the filter holder. If the desired vacuum is exceeded, either leak-check at this higher vacuum or end the leak check as shown below and start over.

When the leak-check is completed, first slowly remove the plug from the inlet to the probe, filter holder, or cyclone (if applicable) and immediately turn off the vacuum pump. This prevents the water in the impingers from being forced backward into the filter holder and silica gel from being entrained backward into the third impinger.

4.1.4.2 Leak-Checks During Sample Run. If, during the sampling run, a component (e.g., filter assembly or impinger) change becomes necessary, a leak-check shall be conducted immediately before the change is made. The leak-check shall be done according to the procedure outlined in Section 4.1.4.1 above, except that it shall be done at a vacuum equal to or greater than the maximum value recorded up to that point in the test. If the leakage rate is found to be no greater than 0.00057 m^3/min (0.02 cfm) or 4 percent of the average sampling rate (whichever is less), the results are acceptable, and no correction will need to be applied to the total volume of dry gas metered; if, however, a higher leakage rate is obtained, the tester shall either record the leakage rate and plan to correct the sample volume as shown in Section 6.3 of this method, or shall void the sampling run.

Immediately after component changes, leak-checks are optional; if such leak-checks are done, the procedure outlined in Section 4.1.4.1 above shall be used.

4.1.4.3 Post-test Leak-Check. A leak-check is mandatory at the conclusion of each sampling run. The leak-check shall be done in accordance with the procedures outlined in Section 4.1.4.1, except that it shall be conducted at a vacuum equal to or greater than the maximum value reached during the sampling run. If the leakage rate is found to be no greater than 0.00057 m^3/min (0.02 cfm) or 4 percent of the average sampling rate (whichever is less), the results are acceptable, and no correction need be applied to the total volume of dry gas metered. If, however, a higher leakage rate is obtained, the tester shall either record the leakage rate and correct the sample volume as shown in Section 6.3 of this method, or shall void the sampling run.

4.1.5 Particulate Train Operation. During the sampling run, maintain an isokinetic sampling rate (within 10 percent of true isokinetic unless otherwise specified by the Administrator) and a temperature around the filter of 120 ± 14°C (248 ± 25°F), or such other temperature as specified by an applicable subpart of the standards or approved by the Administrator.

For each run, record the data required on a data sheet such as the one shown in Figure 5-2. Be sure to record the initial dry gas meter reading. Record the dry gas meter readings at the beginning and end of each sampling time increment, when changes in flow rates are made, before and after each leak check, and when sampling is halted. Take other readings required by Figure 5-2 at least once at each sample point during each time increment and additional readings when significant changes (20 percent variation in velocity head readings) necessitate additional adjustments in flow rate. Level and zero the manometer. Because the manometer level and zero may drift due to vibrations and temperature changes, make periodic checks during the traverse.

Clean the portholes prior to the test run to minimize the chance of sampling deposited material. To begin sampling, remove the nozzle cap, verify that the filter and probe heating systems are up to temperature, and that the pitot tube and probe are properly positioned. Position the nozzle at the first traverse point with the tip pointing directly into the gas stream. Immediately start the pump and adjust the flow to isokinetic conditions. Nomographs are available, which aid in the rapid adjustment of the isokinetic sampling rate without excessive computations. These nomographs are designed for use when the Type S pitot tube coefficient is 0.85 ± 0.02, and the stack gas equivalent density (dry molecular weight) is equal to 29 ± 4. APTD-0576 details the procedure for using the nomographs. If C_p and M_d are outside the above stated ranges, do not use the nomographs unless appropriate steps (see Citation 7 in Section 7) are taken to compensate for the deviations.

PLANT ____________

LOCATION ____________

OPERATOR ____________

DATE ____________

RUN NO. ____________

SAMPLE BOX NO. ____________

METER BOX NO. ____________

METER $\Delta H_@$ ____________

C FACTOR ____________

PITOT TUBE COEFFICIENT, C_p ____________

SCHEMATIC OF STACK CROSS SECTION

AMBIENT TEMPERATURE ____________

BAROMETRIC PRESSURE ____________

ASSUMED MOISTURE, % ____________

PROBE LENGTH, m (ft) ____________

NOZZLE IDENTIFICATION NO. ____________

AVERAGE CALIBRATED NOZZLE DIAMETER, cm (in.) ____________

PROBE HEATER SETTING ____________

LEAK RATE, m^3/min. (cfm) ____________

PROBE LINER MATERIAL ____________

STATIC PRESSURE, mm Hg (in. Hg) ____________

FILTER NO. ____________

TRAVERSE POINT NUMBER	SAMPLING TIME (θ), min.	VACUUM mm Hg (in Hg)	STACK TEMPERATURE (T_S) °C (°F)	VELOCITY HEAD (ΔP_S), mm (in.) H_2O	PRESSURE DIFFERENTIAL ACROSS ORIFICE METER mm H_2O (in. H_2O)	GAS SAMPLE VOLUME m^3 (ft^3)	GAS SAMPLE TEMPERATURE AT DRY GAS METER		FILTER HOLDER TEMPERATURE °C (°F)	TEMPERATURE OF GAS LEAVING CONDENSER OR LAST IMPINGER, °C (°F)
							INLET °C (°F)	OUTLET °C (°F)		
TOTAL							Avg.	Avg.		
AVERAGE							Avg.			

Figure 5-2. Particulate field data.

When the stack is under significant negative pressure (height of impinger stem), take care to close the coarse adjust valve before inserting the probe into the stack to prevent water from backing into the filter holder. If necessary, the pump may be turned on with the coarse adjust valve closed.

When the probe is in position, block off the openings around the probe and porthole to prevent unrepresentative dilution of the gas stream.

Traverse the stack cross-section, as required by Method 1 or as specified by the Administrator, being careful not to bump the probe nozzle into the stack walls when sampling near the walls or when removing or inserting the probe through the portholes; this minimizes the chance of extracting deposited material.

During the test run, make periodic adjustments to keep the temperature around the filter holder at the proper level; add more ice and, if necessary, salt to maintain a temperature of less than 20°C (68°F) at the condenser/silica gel outlet. Also, pericdically check the level and zero of the manometer.

If the pressure drop across the filter becomes too high, making isokinetic sampling difficult to maintain, the filter may be replaced in the midst of a sample run. It is recommended that another complete filter assembly be used rather than attempting to change the filter itself. Before a new filter assembly is installed, conduct a leak-check (see Section 4.1.4.2). The total particulate weight shall include the summation of all filter assembly catches.

A single train shall be used for the entire sample run, except in cases where simultaneous sampling is required in two or more separate ducts or at two or more different locations within the same duct, or, in cases where equipment failure necessitates a change of trains. In all other situations, the use of two or more trains will be subject to the approval of the Administrator.

Note that when two or more trains are used, separate analyses of the front-half and (if applicable) impinger catches from each train shall be performed, unless identical nozzle sizes were used on all trains, in which case, the front-half catches from the individual trains may be combined (as may the impinger catches) and one analysis of front-half catch and one analysis of impinger catch may be performed. Consult with the Administrator for details concerning the calculation of results when two or more trains are used.

At the end of the sample run, turn off the coarse adjust valve, remove the probe and nozzle from the stack, turn off the pump, record the final dry gas meter reading, and conduct a post-test leak-check, as outlined in Section 4.1.4.3. Also, leak-check the pitot lines as described in Method 2, Section 3.1; the lines must pass this leak-check, in order to validate the velocity head data.

4.1.6 Calculation of Percent Isokinetic. Calculate percent isokinetic (see Calculations, Section 6) to determine whether the run was valid or another test run should be made. If there was difficulty in maintaining isokinetic rates due to source conditions, consult with the Administrator for possible variance on the isokinetic rates.

4.2 Sample Recovery. Proper cleanup procedure begins as soon as the probe is removed from the stack at the end of the sampling period. Allow the probe to cool.

When the probe can be safely handled, wipe off all external particulate matter near the tip of the probe nozzle and place a cap over it to prevent losing or gaining particulate matter. Do not cap off the probe tip tightly while the sampling train is cooling down as this would create a vacuum in the filter holder, thus drawing water from the impingers into the filter holder.

Before moving the sample train to the cleanup site, remove the probe from the sample train, wipe off the silicone grease, and cap the open outlet of the probe. Be careful not to lose any condensate that might be present. Wipe off the silicone grease from the filter inlet where the probe was fastened and cap it. Remove the umbilical cord from the last impinger and cap the impinger. If a flexible line is used between the first impinger or condenser and the filter holder, disconnect the line at the filter holder and let any condensed water or liquid drain into the impingers or condenser. After wiping off the silicone grease, cap off the filter holder outlet and impinger inlet. Either ground-glass stoppers, plastic caps, or serum caps may be used to close these openings.

Transfer the probe and filter-impinger assembly to the cleanup area. This area should be clean and protected from the wind so that the chances of contaminating or losing the sample will be minimized.

Save a portion of the acetone used for cleanup as a blank. Take 200 ml of this acetone directly from the wash bottle being used and place it in a glass sample container labeled "acetone blank."

Inspect the train prior to and during disassembly and note any abnormal conditions. Treat the samples as follows:

Container No. 1. Carefully remove the filter from the filter holder and place it in its identified petri dish container. Use a pair of tweezers and/or clean disposable surgical gloves to handle the filter. If it is necessary to fold the filter, do so such that the particulate cake is inside the fold. Carefully transfer to the petri dish any particulate matter and/or filter fibers which adhere to the filter holder gasket, by using a dry Nylon bristle brush and/or a sharp-edged blade. Seal the container.

Container No. 2. Taking care to see that dust on the outside of the probe or other exterior surfaces does not get into the sample, quantitatively recover particulate matter or any condensate from the probe nozzle, probe fitting, probe liner, and front half of the filter holder by washing these components with acetone and placing the wash in a glass container. Distilled water may be used instead of acetone when approved by the Administrator and shall be used when specified by the Administrator; in these cases, save a water blank and follow the Administrator's directions on analysis. Perform the acetone rinses as follows:

Carefully remove the probe nozzle and clean the inside surface by rinsing with acetone from a wash bottle and brushing with a Nylon bristle brush. Brush until the acetone rinse shows no visible particles, after which make a final rinse of the inside surface with acetone..

Brush and rinse the inside parts of the Swagelok fitting with acetone in a similar way until no visible particles remain.

Rinse the probe liner with acetone by tilting and rotating the probe while squirting acetone into its upper end so that all inside surfaces will be wetted with acetone. Let the acetone drain from the lower end into the sample container. A funnel (glass or polyethylene) may be used to aid in transferring liquid washes to the container. Follow the acetone rinse with a probe brush. Hold the probe in an inclined position, squirt acetone into the upper end as the probe brush is being pushed with a twisting action through the probe; hold a sample container underneath the lower end of the probe, and catch any acetone and particulate matter which is brushed from the probe. Run the brush through the probe three times or more until no visible particulate matter is carried out with the acetone or until none remains in the probe liner on visual inspection. With stainless steel or other metal probes, run the brush through in the above prescribed manner at least six times since metal probes have small crevices in which particulate matter can be entrapped. Rinse the brush with acetone, and quantitatively collect these washings in the sample container. After the brushing, make a final acetone rinse of the probe as described above.

It is recommended that two people be used to clean the probe to minimize sample losses. Between sampling runs, keep brushes clean and protected from contamination.

After ensuring that all joints have been wiped clean of silicone grease, clean the inside of the front half of the filter holder by rubbing the surfaces with a Nylon bristle brush and rinsing with acetone. Rinse each surface three times or more if needed to remove visible particulate. Make a final rinse of the brush and filter holder. Carefully rinse out the glass cyclone, also (if applicable). After all acetone washings and particulate matter have been collected in the sample container, tighten the lid on the sample container so that acetone will not leak out when it is shipped to the laboratory. Mark the height of the fluid level to determine whether or not leakage occurred during transport. Label the container to clearly identify its contents.

Container No. 3. Note the color of the indicating silica gel to determine if it has been completely spent and make a notation of its condition. Transfer the silica gel from the fourth impinger to its original container and seal. A funnel may make it easier to pour the silica gel without spilling. A rubber policeman may be used as an aid in removing the silica gel from the impinger. It is not necessary to remove the small amount of dust particles that may adhere to the impinger wall and are difficult to remove. Since the gain in weight is to be used for moisture calculations, do not use any water or other liquids to transfer the silica gel. If a balance is available in the field, follow the procedure for container No. 3 in Section 4.3.

Impinger Water. Treat the impingers as follows: Make a notation of any color or film in the liquid catch. Measure the liquid which is in the first three impingers to within ±1 ml by using a graduated cylinder or by weighing it to within ±0.5 g by using a balance (if one is available). Record the volume or weight of liquid present. This information is required to calculate the moisture content of the effluent gas.

Discard the liquid after measuring and recording the volume or weight, unless analysis of the impinger catch is required (see Note, Section 2.1.7).

If a different type of condenser is used, measure the amount of moisture condensed either volumetrically or gravimetrically.

Whenever possible, containers should be shipped in such a way that they remain upright at all times.

4.3 Analysis. Record the data required on a sheet such as the one shown in Figure 5-3. Handle each sample container as follows:

Container No. 1. Leave the contents in the shipping container or transfer the filter and any loose particulate from the sample container to a tared glass weighing dish. Desiccate for 24 hours in a desiccator containing anhydrous calcium sulfate. Weigh to a constant weight and report the results to the nearest 0.1 mg. For purposes of this Section, 4.3, the term "constant weight" means

Plant ______________________________

Date ______________________________

Run No. ______________________________

Filter No. ______________________________

Amount liquid lost during transport ______________________________

Acetone blank volume, ml ______________________________

Acetone wash volume, ml ______________________________

Acetone blank concentration, mg/mg (equation 5-4) ______________________________

Acetone wash blank, mg (equation 5-5) ______________________________

CONTAINER NUMBER	WEIGHT OF PARTICULATE COLLECTED, mg		
	FINAL WEIGHT	TARE WEIGHT	WEIGHT GAIN
1			
2			
TOTAL	☒	☒	
		Less acetone blank	
		Weight of particulate matter	

	VOLUME OF LIQUID WATER COLLECTED		
	IMPINGER VOLUME, ml	SILICA GEL WEIGHT, g	
FINAL			
INITIAL			
LIQUID COLLECTED			
TOTAL VOLUME COLLECTED		g*	ml

*CONVERT WEIGHT OF WATER TO VOLUME BY DIVIDING TOTAL WEIGHT INCREASE BY DENSITY OF WATER (1g/ml).

$$\frac{\text{INCREASE, g}}{1\ \text{g/ml}} = \text{VOLUME WATER, ml}$$

Figure 5-3. Analytical data.

a difference of no more than 0.5 mg or 1 percent of total weight less tare weight, whichever is greater, between two consecutive weighings, with no less than 6 hours of desiccation time between weighings.

Alternatively, the sample may be oven dried at 105°C (220°F) for 2 to 3 hours, cooled in the desiccator, and weighed to a constant weight, unless otherwise specified by the Administrator. The tester may also opt to oven dry the sample at 105°C (220°F) for 2 to 3 hours, weigh the sample, and use this weight as a final weight.

Container No. 2. Note the level of liquid in the container and confirm on the analysis sheet whether or not leakage occurred during transport. If a noticeable amount of leakage has occurred, either void the sample or use methods, subject to the approval of the Administrator, to correct the final results. Measure the liquid in this container either volumetrically to ±1 ml or gravimetrically to ±0.5 g. Transfer the contents to a tared 250-ml beaker and evaporate to dryness at ambient temperature and pressure. Desiccate for 24 hours and weigh to a constant weight. Report the results to the nearest 0.1 mg.

Container No. 3. Weigh the spent silica gel (or silica gel plus impinger) to the nearest 0.5 g using a balance. This step may be conducted in the field.

"Acetone Blank" Container. Measure acetone in this container either volumetrically or gravimetrically. Transfer the acetone to a tared 250-ml beaker and evaporate to dryness at ambient temperature and pressure. Desiccate for 24 hours and weigh to a constant weight. Report the results to the nearest 0.1 mg.

Note: At the option of the tester, the contents of Container No. 2 as well as the acetone blank container may be evaporated at temperatures higher than ambient. If evaporation is done at an elevated temperature, the temperature must be below the boiling point of the solvent; also, to prevent "bumping," the evaporation process must be closely supervised, and the contents of the beaker must be swirled occasionally to maintain an even temperature. Use extreme care, as acetone is highly flammable and has a low flash point.

5. Calibration

Maintain a laboratory log of all calibrations.

5.1 Probe Nozzle. Probe nozzles shall be calibrated before their initial use in the field. Using a micrometer, measure the inside diameter of the nozzle to the nearest 0.025 mm (0.001 in.). Make three separate measurements using different diameters each time, and obtain the average of the measurements. The difference between the high and low numbers shall not exceed 0.1 mm (0.004 in.). When nozzles become nicked, dented, or corroded, they shall be reshaped, sharpened, and recalibrated before use. Each nozzle shall be permanently and uniquely identified.

5.2 Pitot Tube. The Type S pitot tube assembly shall be calibrated according to the procedure outlined in Section 4 of Method 2.

5.3 Metering System. Before its initial use in the field, the metering system shall be calibrated according to the procedure outlined in APTD-0576. Instead of physically adjusting the dry gas meter dial readings to correspond to the wet test meter readings, calibration factors may be used to mathematically correct the gas meter dial readings to the proper values. Before calibrating the metering system, it is suggested that a leak-check be conducted. For metering systems having diaphragm pumps, the normal leak-check procedure will not detect leakages within the pump. For these cases the following leak-check procedure is suggested: make a 10-minute calibration run at 0.00057 m^3/min (0.02 cfm); at the end of the run, take the difference of the measured wet test meter and dry gas meter volumes; divide the difference by 10, to get the leak rate. The leak rate should not exceed 0.00057 m^3/min (0.02 cfm).

After each field use, the calibration of the metering system shall be checked by performing three calibration runs at a single, intermediate orifice setting (based on the previous field test), with the vacuum set at the maximum value reached during the test series. To adjust the vacuum, insert a valve between the wet test meter and the inlet of the metering system. Calculate the average value of the calibration factor. If the calibration has changed by more than 5 percent, recalibrate the meter over the full range of orifice settings, as outlined in APTD-0576.

Alternative procedures, e.g., using the orifice meter coefficients, may be used, subject to the approval of the Administrator.

Note: If the dry gas meter coefficient values obtained before and after a test series differ by more than 5 percent, the test series shall either be voided, or calculations for the test series shall be performed using whichever meter coefficient value (i.e., before or after) gives the lower value of total sample volume.

5.4 Probe Heater Calibration. The probe heating system shall be calibrated before its initial use in the field according to the procedure outlined in APTD-0576. Probes constructed according to APTD-0581 need not be calibrated if the calibration curves in APTD-0576 are used.

5.5 Temperature Gauges. Use the procedure in Section 4.3 of Method 2 to calibrate in-stack temperature gauges. Dial thermometers, such as are used for the dry gas meter and condenser outlet, shall be calibrated against mercury-in-glass thermometers.

5.6 Leak Check of Metering System Shown in Figure 5-1. That portion of the sampling train from the pump to the orifice meter should be leak checked prior to initial use and after each shipment. Leakage after the pump will result in less volume being recorded than is actually sampled. The following procedure is suggested (see Figure 5-4): Close the main valve on the meter box. Insert a one-hole rubber stopper with rubber tubing attached into the orifice exhaust pipe. Disconnect and vent the low side of the orifice manometer. Close off the low side orifice tap. Pressurize the system to 13 to 18 cm (5 to 7 in.) water column by blowing into the rubber tubing. Pinch off the tubing and observe the manometer for one minute. A loss of pressure on the manometer indicates a leak in the meter box; leaks, if present, must be corrected.

5.7 Barometer. Calibrate against a mercury barometer.

6. Calculations

Carry out calculations, retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after the final calculation. Other forms of the equations may be used as long as they give equivalent results.

6.1 Nomenclature.

A_n = Cross-sectional area of nozzle, m^2 (ft^2).

B_{ws} = Water vapor in the gas stream, proportion by volume.

C_a = Acetone blank residue concentration, mg/g.

c_s = Concentration of particulate matter in stack gas, dry basis, corrected to standard conditions, g/dscm (g/dscf).

I = Percent of isokinetic sampling.

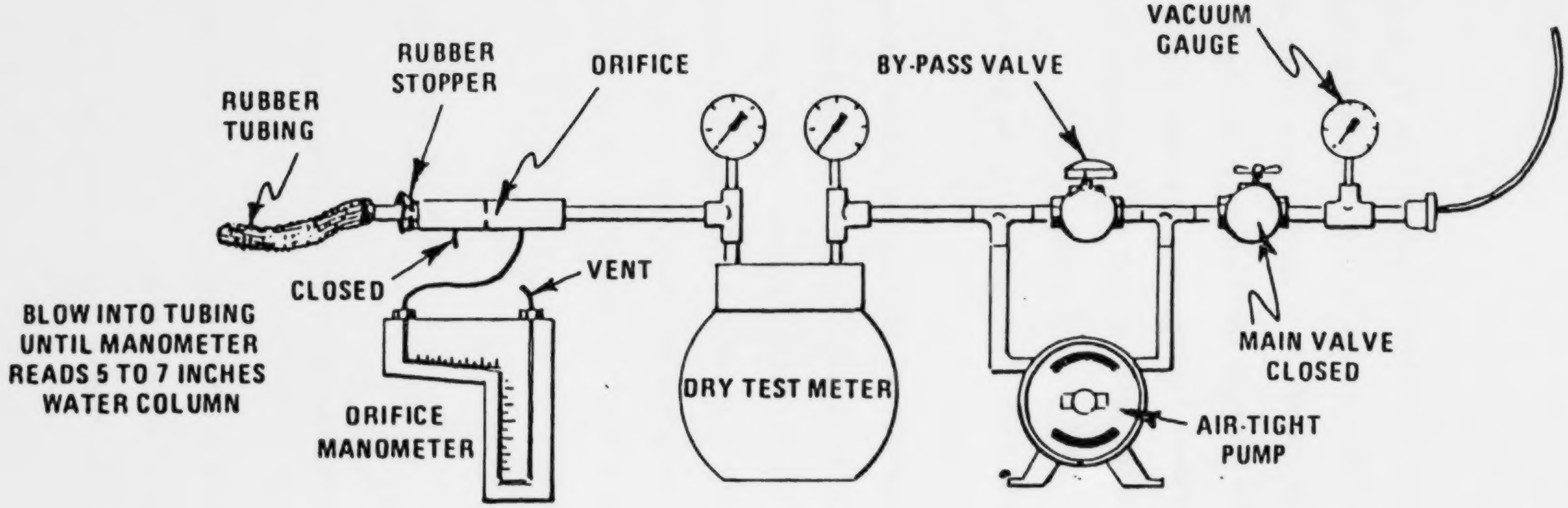

RUBBER TUBING
RUBBER STOPPER
ORIFICE
BY-PASS VALVE
VACUUM GAUGE
CLOSED
VENT
BLOW INTO TUBING UNTIL MANOMETER READS 5 TO 7 INCHES WATER COLUMN
ORIFICE MANOMETER
DRY TEST METER
MAIN VALVE CLOSED
AIR-TIGHT PUMP

Figure 5-4. Leak check of meter box.

L_a = Maximum acceptable leakage rate for either a pretest leak check or for a leak check following a component change; equal to 0.00057 m^3/min (0.02 cfm) or 4 percent of the average sampling rate, whichever is less.

L_i = Individual leakage rate observed during the leak check conducted prior to the "ith" component change (i = 1, 2, 3....n), m^3/min (cfm).

L_p = Leakage rate observed during the post-test leak check, m^3/min (cfm).

m_n = Total amount of particulate matter collected, mg.

M_w = Molecular weight of water, 18.0 g/g-mole (18.0 lb/lb-mole).

m_a = Mass of residue of acetone after evaporation, mg.

P_{bar} = Barometric pressure at the sampling site, mm Hg (in. Hg).

P_s = Absolute stack gas pressure, mm Hg (in. Hg).

P_{std} = Standard absolute pressure, 760 mm Hg (29.92 in. Hg).

R = Ideal gas constant, 0.06236 mm Hg-m^3/°K-g-mole (21.85 in. Hg-ft^3/°R-lb-mole).

T_m = Absolute average dry gas meter temperature (see Figure 5-2), °K (°R).

T_s = Absolute average stack gas temperature (see Figure 5-2), °K (°R).

T_{std} = Standard absolute temperature, 293°K (528°R).

V_a = Volume of acetone blank, ml.

V_{aw} = Volume of acetone used in wash, ml.

V_{lc} = Total volume of liquid collected in impingers and silica gel (see Figure 5-3), ml.

V_m = Volume of gas sample as measured by dry gas meter, dcm (dcf).

$V_{m(std)}$ = Volume of gas sample measured by the dry gas meter, corrected to standard conditions, dscm (dscf).

$V_{w(std)}$ = Volume of water vapor in the gas sample, corrected to standard conditions, scm (scf).

v_s = Stack gas velocity, calculated by Method 2, Equation 2-9, using data obtained from Method 5, m/sec (ft/sec).

W_a = Weight of residue in acetone wash, mg.

Y = Dry gas meter calibration factor.

ΔH = Average pressure differential across the orifice meter (see Figure 5-2), mm H_2O (in. H_2O).

ρ_a = Density of acetone, mg/ml (see label on bottle).

ρ_w = Density of water, 0.9982 g/ml (0.002201 lb/ml).

θ = Total sampling time, min.

θ_1 = Sampling time interval, from the beginning of a run until the first component change, min.

θ_i = Sampling time interval, between two successive component changes, beginning with the interval between the first and second changes, min.

θ_p = Sampling time interval, from the final (n^{th}) component change until the end of the sampling run, min.

13.6 = Specific gravity of mercury.

60 = Sec/min.

100 = Conversion to percent.

6.2 Average dry gas meter temperature and average orifice pressure drop. See data sheet (Figure 5-2).

6.3 Dry Gas Volume. Correct the sample volume measured by the dry gas meter to standard conditions (20°C, 760 mm Hg or 68°F, 29.92 in. Hg) by using Equation 5-1.

$$V_{m(std)} = V_m Y \left(\frac{T_{std}}{T_m}\right)\left[\frac{P_{bar} + \frac{\Delta H}{13.6}}{P_{std}}\right] = K_1 V_m Y \; \frac{P_{bar} + (\Delta H/13.6)}{T_m}$$

Equation 5-1

where:

K_1 = 0.3858 °K/mm Hg for metric units

= 17.64 °R/in. Hg for English units

Note: Equation 5-1 can be used as written unless the leakage rate observed during any of the mandatory leak checks (i.e., the post-test leak check or leak checks conducted prior to component changes) exceeds L_a. If L_p or L_i exceeds L_a, Equation 5-1 must be modified as follows:

(a) Case I. No component changes made during sampling run. In this case, replace V_m in Equation 5-1 with the expression:

$$[V_m - (L_p - L_a)\ \theta]$$

(b) Case II. One or more component changes made during the sampling run. In this case, replace V_m in Equation 5-1 by the expression:

$$[V_m - (L_1 - L_a)\ \theta_1 - \sum_{i=2}^{n} (L_i - L_a)\ \theta_i - (L_p - L_a)\ \theta_p]$$

and substitute only for those leakage rates (L_i or L_p) which exceed L_a.

6.4 Volume of water vapor.

$$V_{w(std)} = V_{1c}\left(\frac{\rho_w}{M_w}\right)\left(\frac{RT_{std}}{P_{std}}\right) = K_2\ V_{1c} \qquad \text{Equation 5-2}$$

where:

K_2 = 0.001333 m^3/ml for metric units

= 0.04707 ft^3/ml for English units.

6.5 Moisture Content.

$$B_{ws} = \frac{V_{w(std)}}{V_{m(std)} + V_{w(std)}} \qquad \text{Equation 5-3}$$

Note: In saturated or water droplet-laden gas streams, two calculations of the moisture content of the stack gas shall be made, one from the impinger analysis (Equation 5-3), and a second from the assumption of saturated conditions. The lower of the two values of B_{ws} shall be considered correct. The procedure for determining the moisture content based upon assumption of saturated conditions is given in the Note of Section 1.2 of Method 4. For the purposes of this method, the average stack gas temperature from Figure 5-2 may be used to make this determination, provided that the accuracy of the in-stack temperature sensor is $\pm$ 1°C (2°F).

6.6 Acetone Blank Concentration.

$$C_a = \frac{m_a}{V_a \rho_a} \qquad \text{Equation 5-4}$$

6.7 Acetone Wash Blank.

$$W_a = C_a V_{aw} \rho_a \qquad \text{Equation 5-5}$$

6.8 Total Particulate Weight. Determine the total particulate catch from the sum of the weights obtained from containers 1 and 2 less the acetone blank (see Figure 5-3). Note: Refer to Section 4.1.5 to assist in calculation of results involving two or more filter assemblies or two or more sampling trains.

6.9 Particulate Concentration.

$$c_s = (0.001 \text{ g/mg}) \; (m_n/V_{m(std)}) \qquad \text{Equation 5-6}$$

6.10 Conversion Factors:

From	To	Multiply by
scf	m^3	0.02832
g/ft^3	gr/ft^3	15.43
g/ft^3	lb/ft^3	2.205×10^{-3}
g/ft^3	g/m^3	35.31

6.11 Isokinetic Variation.

6.11.1 Calculation From Raw Data.

$$I = \frac{100 \; T_s \; [K_3 \; V_{1c} + (V_m \; Y/T_m) \; (P_{bar} + \Delta H/13.6)]}{60 \; \theta \; v_s \; P_s \; A_n}$$

Equation 5-7

where:

K_3 = 0.003454 mm Hg-m^3/ml-°K for metric units

= 0.002669 in. Hg-ft^3/ml-°R for English units.

6.11.2 Calculation From Intermediate Values.

$$I = \frac{T_s V_{m(std)} P_{std} 100}{T_{std} v_s \theta A_n P_s 60 (1-B_{ws})}$$

$$= K_4 \frac{T_s V_{m(std)}}{P_s v_s A_n \theta (1-B_{ws})} \qquad \text{Equation 5-8}$$

where:

K_4 = 4.320 for metric units

= 0.09450 for English units.

6.12 Acceptable Results. If 90 percent $\leq$ I $\leq$ 110 percent, the results are acceptable. If the results are low in comparison to the standard and I is beyond the acceptable range, or, if I is less than 90 percent, the Administrator may opt to accept the results. Use Citation 4 to make judgments. Otherwise, reject the results and repeat the test.

7. Bibliography

1. Addendum to Specifications for Incinerator Testing at Federal Facilities. PHS, NCAPC. Dec. 6, 1967.

2. Martin, Robert M. Construction Details of Isokinetic Source-Sampling Equipment. Environmental Protection Agency. Research Triangle Park, N. C. APTD-0581. April, 1971.

3. Rom, Jerome J. Maintenance, Calibration, and Operation of Isokinetic Source Sampling Equipment. Environmental Protection Agency. Research Triangle Park, N. C. APTD-0576. March, 1972.

4. Smith, W. S., R. T. Shigehara, and W. F. Todd. A Method of Interpreting Stack Sampling Data. Paper Presented at the 63d Annual Meeting of the Air Pollution Control Association, St. Louis, Mo. June 14-19, 1970.

5. Smith, W. S., et al. Stack Gas Sampling Improved and Simplified With New Equipment. APCA Paper No. 67-119. 1967.

6. Specifications for Incinerator Testing at Federal Facilities. PHS, NCAPC. 1967.

7. Shigehara, R.T. Adjustments in the EPA Nomograph for Different Pitot Tube Coefficients and Dry Molecular Weights. Stack Sampling News 2:4-11. October, 1974.

8. Vollaro, R. F. A Survey of Commercially Available Instrumentation For the Measurement of Low-Range Gas Velocities. U. S. Environmental Protection Agency, Emission Measurement Branch. Research Triangle Park, N. C. November, 1976 (unpublished paper).

9. Annual Book of ASTM Standards. Part 26. Gaseous Fuels; Coal and Coke; Atmospheric Analysis. American Society for Testing and Materials. Philadelphia, Pa. 1974. pp. 617-622.